our promise, our performance

the delphi advantage

delphi energy corp. 2005 ANNUAL REPORT

your returns

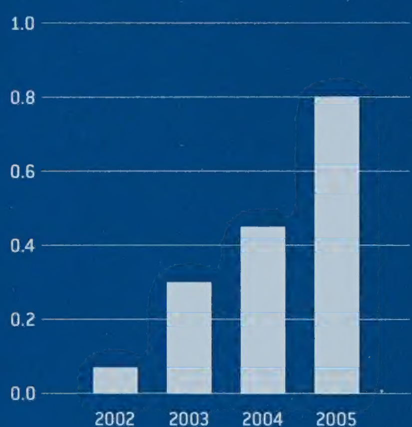
January 12, 2005
Delphi's board of directors appoints Michael Kaluza, P. Eng., as Vice President, Engineering, and Mr. Daniel Labelle, M.Sc., as Manager, Geology.

February 1, 2005
Delphi closes its previously announced $52 million acquisition of natural gas assets at Bigstone in the Company's core area of Berland River in North West Alberta.

March 31, 2005
Delphi closes a $12 million bought-deal private placement financing.

May 5, 2005
Delphi announces its first quarter results, including an increase of 132 percent in cash flow to $5.9 million and an increase of 170 percent in average production to 3,685 boe/d. Current production rises to 4,400 boe/d.

August 11, 2005
Delphi reports record secor
quarter 2005 results, inclu
a 144 percent increase in y
over-year production to 4,1
boe/d. Revenue, cash flow
and earnings also increase
significantly, with Delphi earning $1 million in the quarter.



78%

increase in cash flow per share

45

increase

ovember 9, 2005

Delphi reports record cash flow and earnings in the third quarter of 2005, increasing cash flow by 187 percent to $10.2 million and earning $1.2 million. Production in the quarter reaches 4,152 boe/d.

November 23, 2005

Delphi enters a significant farm-in agreement with a major producer to jointly develop a natural gas resource play in the Bigfoot area of northeast British Columbia. The joint venture is expected to result in 750 to 1,000 net boe/d in 2006 and eventually more than 4,000 boe/d.

December 6, 2005

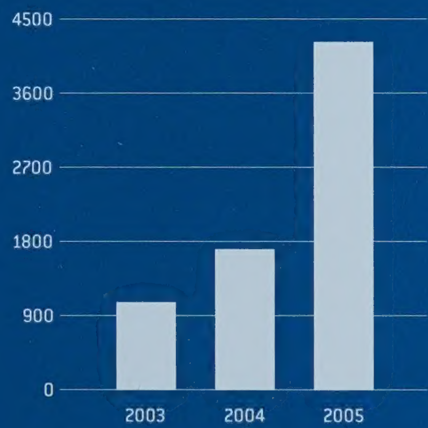
Delphi updates its capital program, including plans to spend $120 million to $125 million in 2006.

December 13, 2005

Delphi closes $14 million flow-through financing.

December 29, 2005

Delphi closes a $14 million bought-deal private placemen financing.



5%

reserves

147%

increase in production

2005 highlights

Year Ended December 31	2005	2004
FINANCIAL HIGHLIGHTS ($000s except per boe and per share amounts)		
Gross petroleum and natural gas sales	$ 80,880	$ 24,474
Per boe	52.48	39.19
Funds from operations	40,212	12,125
Per boe	26.09	19.41
Per share – basic	0.80	0.45
– diluted	0.79	0.43
Net earnings	6,677	1,953
Per boe	4.32	3.12
Per share – basic	0.13	0.07
Per share – diluted	0.13	0.07
Capital invested	112,468	85,707
Debt, net	61,020	61,274
Total assets	244,666	171,947
SHARE INFORMATION (000s)		
Shares outstanding		
Basic	55,254	47,704
Diluted	57,883	49,599
OPERATING HIGHLIGHTS		
Average daily production		
Natural gas (mcf/d)	19,848	5,822
Percentage of total production	78%	57%
Oil and NGLs (bbl/d)	913	736
Percentage of total production	22%	43%
Total (boe/d)	4,221	1,706
Realized selling prices		
Natural gas ($/mcf)	9.20	6.74
Oil and NGLs ($bbl/d)	42.78	37.73
Total oil equivalent ($boe/d)	52.48	39.19
Wells drilled (net)	22.6	4.3
Undeveloped land		
Gross acres	272,491	362,732
Net acres	51,836	66,954
Average working interest (%)	19	18.5
Proved plus probable reserves (P+P)		
Natural gas (mmcf)	69,081	42,962
Oil and NGLs (mbbls)	2,911	2,799
Total oil equivalent (mboe)	14,424	9,960
Finding and development costs (P+P) ($/boe)	17.86	16.70
Reserve life index (P+P) (years)	9.4	10.4

A barrel of oil equivalent (boe), derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil, may be misleading, particularly if used in isolation. A boe conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

our company

FOCUS
Focus on areas of expertise

PARTNERSHIPS
Work with industry partners to enhance opportunity flow

THE DELPHI MODEL

BALANCE
Balance low-risk development with high-impact exploration

ACQUISITIONS
Acquisitions that enhance drilling inventory

this is how the model is working through 2005

In 2005, the Company focused on North West Alberta and North East British Columbia natural gas opportunities. In the first quarter of 2005, Delphi acquired natural gas assets at Bigstone, Alberta for $51.3 million and spent the majority of its 2005 capital in the successful re-development and exploitation of the assets. The Company also completed drilling three exploration wells later in the year with a 67 percent success rate. Industry partnerships continue to provide significant opportunities. Late in 2005 the Company entered into a joint venture to exploit a natural gas resource play in North East British Columbia with a senior industry partner. This partnership has the potential to provide a drilling inventory for the next 10 years and beyond.

corporate profile

Delphi Energy Corp. ("Delphi" or "the Company") is positioned for long-term organic growth. In 2005, the Company profited from its 2004 acquisition strategy by unlocking the value in its existing and acquired assets through low-risk development drilling, well workovers and reactivations and facility optimizations. A farm-in agreement with a major producer announced at the end of 2005 has the potential to provide a drilling inventory for the next 10 years and beyond.

The Company started as a private explorer and producer in January 2003, listed with the TSX Venture Exchange in June 2003 and graduated to the Toronto Stock Exchange in August 2004. Delphi trades under the symbol DEE.

Delphi is based in Calgary and operates primarily in North East British Columbia and North West Alberta. The Company's corporate strategy is to focus on its areas of expertise, take advantage of its relationships with major industry partners to enhance opportunities and balance high-impact exploration with low-risk development drilling.

The Company is dedicated to developing its assets, exploring for new opportunities and initiating acquisitions or joint venture deals to grow its natural gas-weighted reserves and production. Investment opportunities and risk profiles will be attentively managed to maintain a solid financial position while focusing on per share value creation.

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our message to shareholders

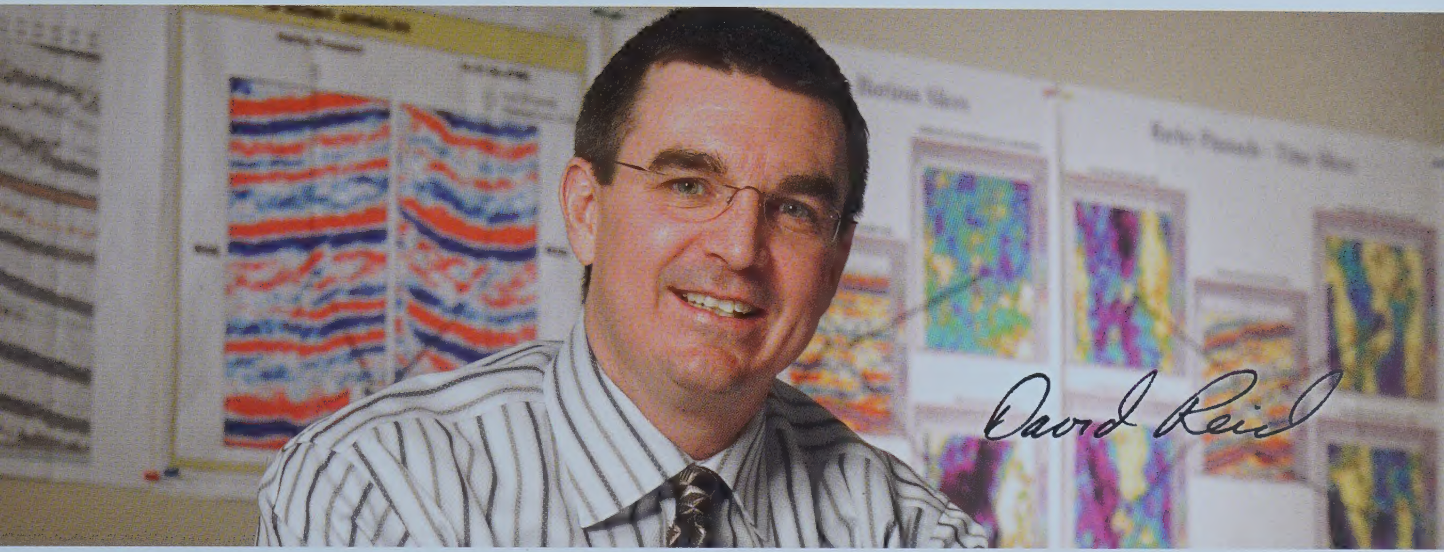
"Delphi has delivered significant growth on all key metrics during 2005, from a capital program focused on our large inventory of development and exploration opportunities."

Average production for 2005 increased 147 percent to 4,221 barrels of oil equivalent per day (boe/d) from 1,706 boe/d in 2004. Cash flow increased to $40.2 million during 2005, a 232 percent increase over 2004. Operating costs during the fourth quarter of 2005 decreased 31 percent over the same period in 2004. The Company also added 6.0 million barrels of oil equivalent of new reserves at a cost of $17.86 per barrel of oil equivalent in 2005 replacing produced volumes by 290 percent. Since the creation of the Company three years ago, Delphi has achieved production per share growth of 110 percent, reserves per share growth of 150 percent, cash flow per share growth of 150 percent and share price growth of 225 percent. With the drilling success we have enjoyed and the significant inventory of growth opportunities, we believe the best is yet to come.

Our successful capital program during 2005 serves as a key measure of our team's abilities. Our team has identified and successfully captured strategic acquisitions and joint ventures over the past year. The $57 million acquisition of a private company at the end of 2004 and the $52 million acquisition of 24,000 acres of natural gas properties at Bigstone, Alberta in the first quarter of 2005 redefined the Company. In 2005, our team went to work on the acquired properties with a low-risk capital program designed to deliver growth. The plan was successful. Despite industry wide challenges with rig availability and unusually wet weather in the spring that delayed the start of the summer drilling program, Delphi exited the year at approximately 5,500 boe/d. We were able to execute our drilling program in 2005 as a result of good planning. We secured access to services early to ensure we could complete our program. At the beginning of 2005, we had a plan to drill 40 wells over the year. The program was increased to 45 wells drilled (22.6 net) in 2005 with a net success rate of 91 percent. Our 2005 capital program delivered some exciting results. We achieved 125 percent growth in production at Bigstone and increased reserves by 89 percent. The Company has maintained a strategy of utilizing a higher component of debt than equity over the last two years to fund our acquisitions, in order to reduce the dilutive effect of incremental equity. The basis of this strategy is our confidence in our solid producing asset base, an active commodity hedging program and a well managed low-risk capital program that is designed to deliver predictable production, reserve, and cash flow growth. At December 31, 2005, we had a debt to cash flow ratio of 0.9 to 1.0 based on fourth quarter annualized cash flow, a significant drop from a ratio of 3.0 to 1.0 at the beginning of the year based on first quarter annualized cash flow. Benefiting from low interest rates and high commodity prices, our approach to funding our capital requirements proved effective for shareholders.

Not only did Delphi grow on all key measures in 2005, we have also been actively growing our team. Thanks to our culture and compensation package -- crafted to make owners out of employees – our team continued to grow and perform in 2005. We started as a private company with two people, and have recently hired our 22nd person at the start of 2006. With four geologists, a geophysicist and five engineers, we have three multi-disciplinary technical teams maximizing the current asset base with another team dedicated to pursuing new opportunities.

A new opportunity recently captured by Delphi was a joint venture announced at the end of 2005 with a major producer in the Bigfoot area of North East British Columbia, to jointly develop a natural gas play on 138,000 gross acres. The arrangement also has exploration potential on an additional 128,000 gross acres with an area of mutual interest. Bigfoot can be most easily described as a significant acquisition of reserves, paid for over a two year period, utilizing development capital. There is an estimated one trillion cubic feet of gas in place within the Jean Marie formation at depths of approximately 2,000 meters. Delphi's 50 percent share of this significant resource could be as much as 300 to 400 billion cubic feet of recoverable gas or almost fives times the current reserve



base of the Company. Although it's difficult to forecast the long-term implications of this opportunity, we are estimating a near term increase of 750 to 1,000 boe/d in 2006 and more than 4,000 boe/d in a few years, with a drilling inventory that provides the Company with five to ten years of growth opportunities.

OUTLOOK

Delphi continues to gain momentum, expecting to spend $120.0 to $125.0 million on capital projects during 2006, split 90 percent to development and 10 percent to exploration. The Company is forecasting 2006 production to average approximately 7,000 boe/d with an exit rate of approximately 8,000 boe/d. The 2006 capital program will have a similar risk profile to 2005, with 90 percent of the capital program focused on development projects, drilling 72 wells (27 net after earning) in 2006 with almost 50 percent of the drilling being completed during the first quarter of 2006. Over the last three months, Delphi has had up to four to five operated rigs and another six to eight non-operated rigs running at any given time. Cash flow is anticipated to be approximately $70.0 million in 2006, a 65 percent increase over 2005. At this time the Company is maintaining its expectations for 2006 natural gas prices to average CDN $7.70 per gigajoule (AECO). Delphi expects the inflationary pressures of the cost of services to moderate during 2006 with the softening of near-term natural gas prices. Currently, approximately 30 percent of the Company's natural gas production is contracted through the remainder of 2006 with a floor of CDN $9.00 per gigajoule. The debt to cash flow ratio for 2006 is expected to peak at approximately 2.0 to 1.0 through the first half of 2006 and decrease to approximately 1.4 to 1.0 by the end of the year.

The Company has become entirely focused within its core areas of North West Alberta and North East British Columbia. With the successful results of its capital programs in those areas, Delphi is contemplating the disposition of its assets in East Central Alberta during 2006. East Central Alberta has become a minor non-core area for the Company. The proceeds from such a disposition would be used to partially fund Delphi's active 2006 capital program. The Company is focused on growing an asset base of high quality reserves and production, with a constant effort to drive production costs lower year over year. This allows the Company to deliver growth efficiently in a volatile commodity price environment. Those efforts were successful in 2005. Operating costs in 2006 are expected to be 15 to 20 percent lower than 2005. Delphi's reserve base over the past three years has grown by over 600 percent to 14.4 million boe at the end of 2005. The independent engineering evaluation of the Company's oil and natural gas reserves, prepared in accordance with NI 51-101, captures very little of the future potential of the projects currently being developed. Existing developed reserves represent approximately 87 percent of the December 31, 2005 total reserve value. Delphi expects to be able to maintain this growth profile over the next several years. A focus on low to moderate risk projects and a continued effort towards efficient cost of services should also result in lower finding and development costs over the next two to three years.

Delphi's inventory of drilling opportunities in its existing core properties and the recent addition of the Bigfoot Joint Venture creates a visible low-risk growth platform from which to work from the next five to 10 years. In addition, Delphi's technical teams continue to develop and pursue new opportunities to add to the Company's inventory of opportunities. The 2006 capital program is well under way with a very active winter program coming to an end. In terms of results, Delphi believes the best is yet to come.

On behalf of the Board,

David J. Reid
President and Chief Executive Officer
March 13, 2006

our operations

OUR PROMISE: Increase production and generate funds from operations of $40 million

OUR PERFORMANCE: In 2005, Delphi increased production by 147 percent to 4,221 boe/d and with the combination of increased commodity prices, achieved funds from operations of $40.2 million or $0.80 per share.

147%

increase in production

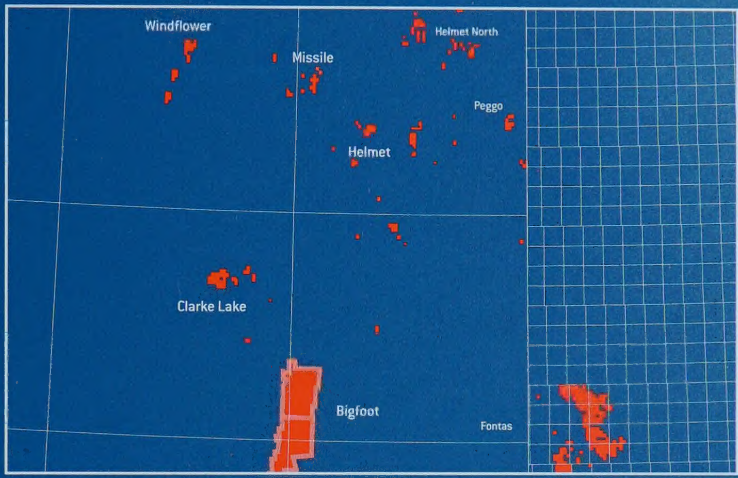
REVIEW OF OPERATIONS

Delphi achieved significant production and reserves growth in 2005 through a focused approach of acquiring underexploited assets and utilizing the technical strength of the "Delphi Team" to unlock the value in the Company's newly acquired and existing assets. The Company successfully pursued low-risk development drilling, well reworks/reactivations and facility optimizations. In addition, Delphi made significant progress converting its exploration prospects into proved reserves with offset and uphole potential that will provide future development opportunities. To enhance the inventory of long-term, low-risk development growth opportunities, the Company entered into a farm-in agreement to exploit a natural gas resource play in North East British Columbia, with a senior industry producer. This partnership has the potential to provide a drilling inventory for the next 10 years and beyond.

During 2005, Delphi's production averaged 4,221 barrels of oil equivalent per day (boe/d), an increase of 147 percent from the 2004 average of 1,706 boe/d. The largest gain in production and reserves was due to the re-development of the Bigstone property, which resulted in a 125 percent increase from approximately 1,200 boe/d at the time of acquisition to a an average December rate of approximately 2,700 boe/d. The Company will use this property as a benchmark for the development of existing assets and the evaluation of acquisition or farm-in opportunities. In 2005, Delphi participated in drilling 45 (22.6 net) wells, achieving a net success rate of 91 percent. Total capital expenditures excluding acquisitions were $61.2 million, while net acquisition capital was $45.4 million. More than 90 percent of all capital was spent on the North West Alberta and North East British Columbia properties. In addition, the value associated with approximately $4.0 million expended on winter program preparations and exploration wells will not be realized in production or reserves until 2006.

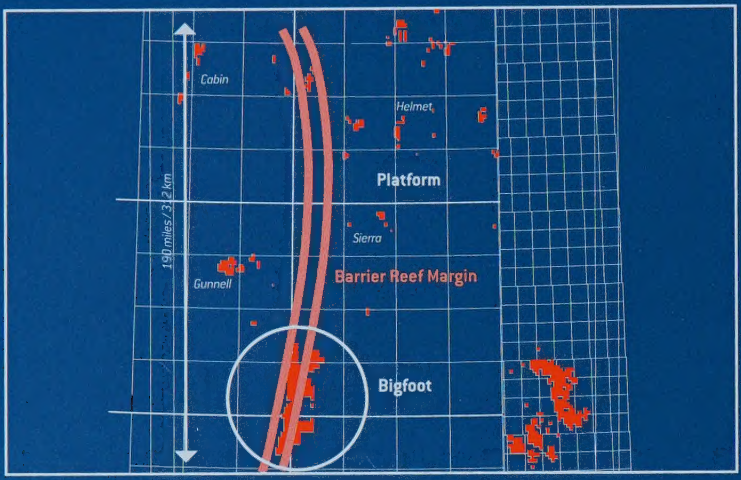
Delphi is anticipating a 2006 capital budget in the range of $120 to $125 million, excluding acquisitions. Approximately 90 percent of the budget will be spent on low-risk development projects, with 70 percent targeting North East British Columbia and 30 percent targeting Alberta properties. Ten percent will be spent on high-impact exploration projects. As a result of the contemplated budget, Delphi expects to drill 72 wells at an average working interest of 38 percent and attempt 27 well reactivations at an average working interest of 59 percent. The Company has budgeted approximately $14.3 million for the acquisition of land and seismic data.

The existing asset base is producing approximately 1,130 boe/d, consisting of 100 percent natural gas and natural gas liquids with an un-developed land base of approximately 19,500 net acres



NEBC

north east **british columbia**



Over the next five years, the Bigfoot joint venture has the potential to double current production rates and triple reserves of the Company.

NORTH EAST BRITISH COLUMBIA

In November, Delphi announced a farm-in agreement with a senior industry producer to jointly develop a natural gas resource play in the Bigfoot area of North East British Columbia. The agreement provides Delphi an opportunity to earn a 50 percent working interest in excess of 200 sections of land. An Area of Mutual Interest (AMI) has been established, which covers more than 200 additional sections of land. The lands earned are anticipated to generate development and exploration drilling opportunities for the next five to 10 years at a rate of about 30 wells per year. Delphi's preliminary 2006 production estimates from the joint venture range from 750 to 1,000 boe/d. Over the next five years, the Bigfoot joint venture has the potential to double current production rates and triple reserves of the Company. If successful, continued development drilling to exploit the primary and secondary potential on the earned lands and lands within the Area of Mutual Interest could extend well beyond 10 years.

The Bigfoot joint venture is an excellent complement to Delphi's existing asset base in North East British Columbia which was acquired from a private company in December 2004. The existing asset base is producing approximately 1,130 boe/d, consisting of 100 percent natural gas and natural gas liquids with an undeveloped land base of approximately of 19,500 net acres. Delphi spent the majority of 2005 acquiring seismic data, performing technical property evaluations, and obtaining the necessary regulatory approvals to capture the identified upside potential on these assets. This planning phase has generated a significant number of drilling, reactivation, and tie-in projects that will be executed in 2006 and beyond.

BIGFOOT

The Bigfoot joint venture is a natural gas resource play primarily targeting the extensive Jean Marie trend. Significant secondary potential exists in the Cretaceous, Triassic, Mississippian, and Devonian trends that have been proven productive on surrounding acreage and to a limited extent on the lands within the AMI. The Jean Marie trend is considered one of the largest regional plays discovered in the Western Canada Sedimentary Basin in the past decade. To date, in excess of 1,100 wells have been drilled and completed in the Jean Marie formation. Current production is in excess of 465 mmcf/d, with a cumulative recovery of 1.1 trillion cubic feet of gas. Typical Jean Marie wells have an initial production rate of 2,000 mcf/d and will recover two to three billion cubic feet of gas. Delphi's farm-in area is an extension of this prolific trend.

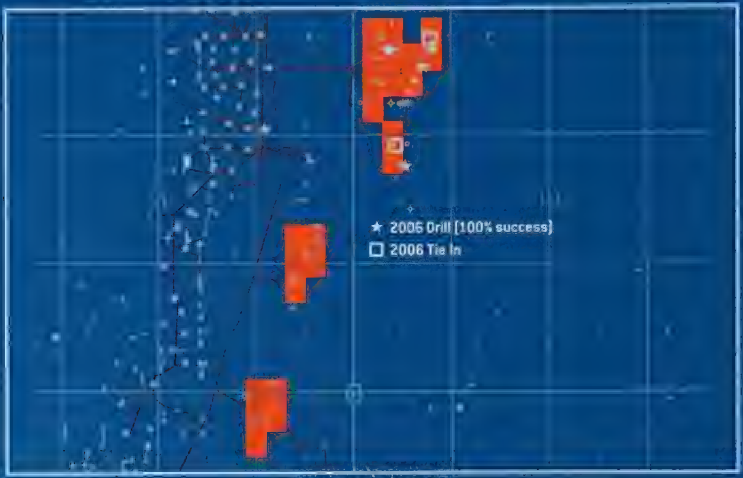
The area has partial 3D seismic coverage and features six pilot wells. Production tests on the pilot wells indicate the reservoir is similar in nature to the main trend. The farm-in earning provision is divided into two phases, with the first phase consisting of installing infrastructure to permit year-round access/development, tie-in of the existing productive wellbores and the drilling of 19 wells in Area 1 during 2006. This activity will earn Delphi a 50 percent working interest in approximately 75,000 acres of land, wells and infrastructure in Area 1. While the indicated activities are anticipated to continue into the third quarter of 2006, first production from the property is anticipated during the first half of 2006. Estimated net production rates are 750 to 1,000 boe/d on a full-year basis. Operations began in Area 1 early in 2006.

The earning provision for the second phase will be initiated with the acquisition of approximately 200 square kilometers of 3D seismic in Area 2 during the first quarter of 2006. Once the seismic is acquired, Delphi will have the option to participate and earn in Area 2 during 2007, with activity levels and terms similar to those for earning in Area 1. The land base associated with Area 2 is approximately 63,000 acres.

The lands earned are anticipated to generate development and exploration drilling opportunities for the next five to 10 years.

BIGFOOT

north east british columbia



WINDFLOWER

During 2005, Delphi acquired additional 2D seismic and identified four low-risk step-out/infill wells and two standing wellbores with gas tests that will be tied-in to the existing infrastructure.

WINDFLOWER

Windflower is primarily a winter access area producing from shallow Permian targets associated with structural highs that can be mapped utilizing 2D seismic. Delphi currently produces approximately 130 net boe/d from two wells. The Company has 3,500 net undeveloped acres at operated and non-operated working interests that vary from 27 to 60 percent.

During 2005, Delphi acquired additional 2D seismic and identified four low-risk step-out/infill wells and two standing wellbores with gas tests that will be tied-in to the existing infrastructure. After maximizing our working interest in the various opportunities through several farm-in agreements, Delphi has committed to the required services and mobilized equipment at year-end to proceed with the identified projects. Success could lead to additional development in this relatively underexplored area.

OTHER PROPERTIES

The remaining Company assets in North East British Columbia produce from various properties and formations, including the shallow Mississippian Debolt at Helmet to the deeper Devonian Jean Marie and Slave Point carbonates at Helmet North, Missile, and Clarke Lake. Delphi currently produces approximately 1,000 net boe/d from these assets and has access to 16,000 net undeveloped acres at operated and non-operated working interests that vary from one to 100 percent.

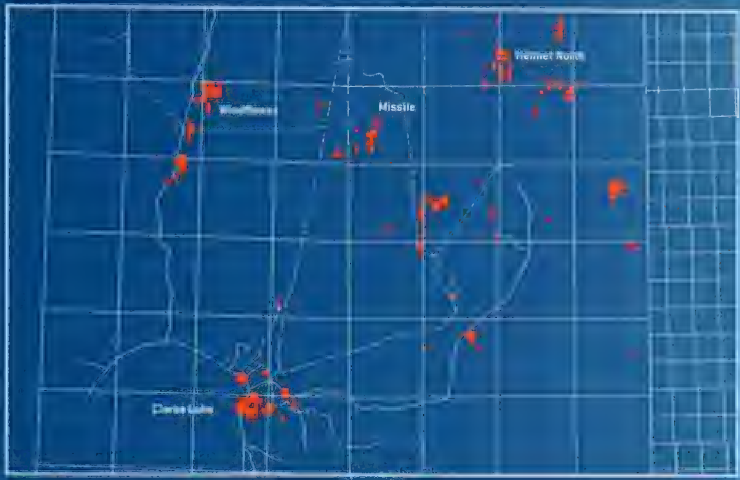
During 2005 the Company incurred capital expenditures of approximately $3.9 million on drilling, tie-ins, and facility optimizations. The timing of acquisition of these properties at the end of 2004 and the nature of the access (primarily winter only) limited the amount of work activity and associated capital in 2005. Even with the limited access Delphi managed to participate in the successful drilling of a well in the Clarke Lake field, complete the tie-in of a stranded well in the Junior area and completed facility modifications at Missile. This activity, in addition to a trade of undeveloped lands in the Missile area for a working interest in three producing wells at Helmet, allowed Delphi to maintain relatively constant production volumes from the area throughout the year, providing a strong base for the proposed 2005/06 winter program.

Technical reviews were also performed on the majority of the Company's properties, which resulted in a comprehensive list of projects to be executed over the next several years. During 2006, Delphi plans to participate in drilling up to 25 wells (10.0 net) and the reactivation/tie-in of an additional seven wells (3.2 net). In addition, we will continue to identify and pursue farm-ins that provide high working interest opportunities with the potential to generate multi-well programs given success in an area.

178%

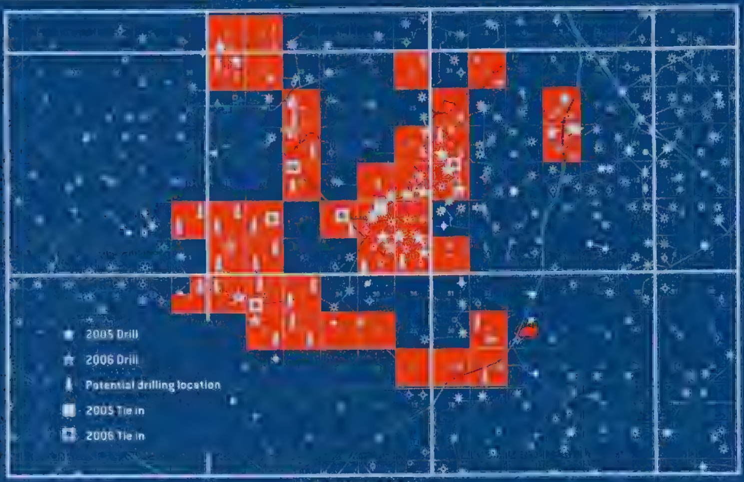
increase in net asset value per share

Delphi plans to participate in drilling up to 25 wells (10.0 net) and the reactivation/tie-in of an additional seven wells (3.2 net).



NEBC

north west alberta



BIGSTONE

Delphi operates in excess of 95 percent of its production in the area and has an undeveloped land base of approximately 4,800 net acres.

NORTH WEST ALBERTA

The three primary areas that make up Delphi's North West Alberta region include: Bigstone/Berland River, Fontas and Grande Prairie. Production characteristics in these areas range from shallow, natural gas development plays at Fontas, multi-zone low-risk development targets at Bigstone, and a combination of multi-zone low-risk development targets and high-impact Devonian targets at Berland River.

In 2005, Delphi had a balanced program of well reactivations in the Grande Prairie area via a Development Joint Venture, an acquisition program with the purchase of the Bigstone property, the drilling of low-risk infill/step-out wells in the Fontas and Bigstone areas, and a high-impact exploration program also in the greater Grande Prairie area. The Company is very pleased to report that each program resulted in success rates exceeding expectations. These activities allowed Delphi to increase North West Alberta production through the year from an average rate in January 2005 of approximately 650 boe/d to in excess of 3,400 boe/d in December 2005.

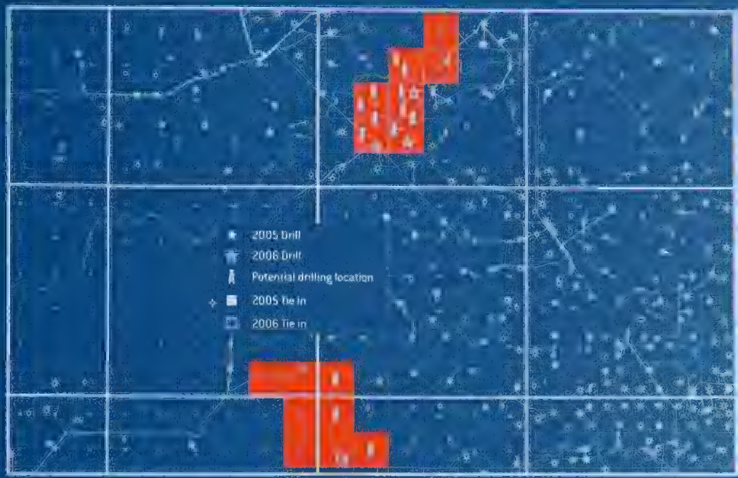
BIGSTONE/BERLAND RIVER

In the Bigstone/Berland River area, Delphi was producing 2,700 boe/d net at December 31, 2005 from 34 wells, consisting of 13.5 mmcf/d of gas and 450 bbl/d of natural gas liquids. Bigstone production is primarily from the Cretaceous Dunvegan sands, however deeper drilling into multiple intervals of the Bullhead group as well as shallower completions in the Cardium have also proven successful. Berland River production is from the Devonian Nisku and Leduc formation but has multi-zone potential in the Cretaceous intervals. Delphi operates in excess of 95 percent of its production in the area and has an undeveloped land base of approximately 4,800 net acres. The Company also has a 29 percent working interest in an 80 mmcf/d gas plant and associated gathering system. The ownership of infrastructure is a key component in the low operating cost for the area which translates to operating netbacks well in excess of $40/boe.

At the time of the acquisition in February 2005, the Bigstone property was producing approximately 1,200 boe/d net from 16 wells, consisting of six mmcf/d of sweet gas and 200 bbl/d of natural gas liquids. After a detailed technical review of the property, the Company was successful in obtaining regulatory approval to downspace the current Dunvegan producers from two to four wells per section which resulted in the drilling of 15 low-risk infill/step-out locations. Several of these wells were deepened to the Bullhead group and were successful in adding production and reserves from this interval. In conjunction with the drilling program, a comprehensive wellbore and facility optimization plan was successful in increasing production from the Bigstone property to approximately 2,700 boe/d net in December. The Company has identified an additional four low-risk locations in Bigstone proper that will be pursued in 2006. The majority of the undeveloped lands (4,250 acres) are located immediately west of Bigstone proper and are accessible primarily in the winter due to the terrain and wildlife. The offset well control and sub-surface mapping indicate this is a highly prospective area for multiple zones similar to the producing intervals in Bigstone proper. Delphi will be pursuing the evaluation of these lands and plans to drill as many as five wells (2.7 net) and tie-in two standing wellbores (0.6 net) during the first quarter of 2006. Success could ultimately result in as many as three to four wells drilled per section to fully exploit the multi-zone potential of the area.

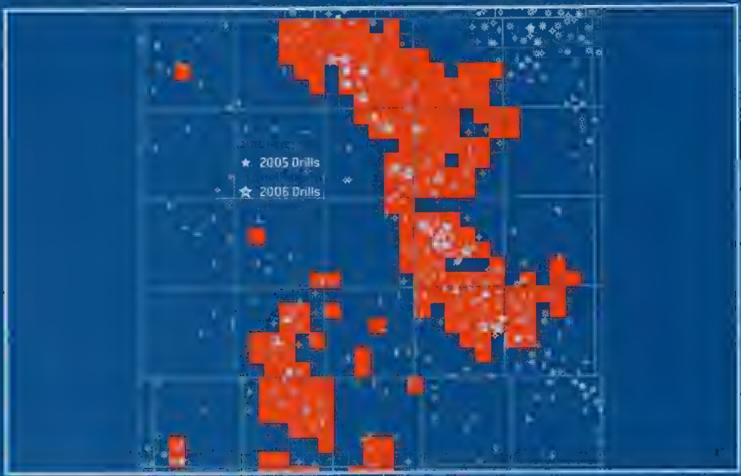
The Berland River property currently produces approximately 55 boe/d from two wells, consisting of 250 mcf/d and a small amount of natural gas liquids. In the Berland River area Delphi has working interests from eight percent to 32 percent in 15 sections of land. The past 18 months have seen a significant increase in development activity with numerous wells drilled on offsetting acreage to develop

The joint interest owners of the Berland River lands have generated an initial development plan to drill four wells (0.4 net) in 2006.



BERLAND RIVER

north west alberta



FONTAS

Based on preliminary results, the Company anticipates similar production performance as experienced in previous years, which would result in a peak net production rate in April 2006 of 700 to 750 boe/d.

the mutli-zone potential of the Cretaceous. Offset operators are initially developing their lands with two wells per section and full field development is typically three to four wells per section. The joint interest owners of the Berland River lands have generated an initial development plan to drill four wells (0.4 net) in 2006. Future development plans call for as many as 11 wells to be drilled over the next two to three years.

FONTAS

At Fontas, Delphi was producing approximately 500 boe/d net consisting of 3000 mcf/d gas through a company owned facility at year-end. Production is primarily from the Mississippian Debolt/ Elkton and the Cretaceous Detrital which are typically less than 800 meters in depth. A combination of sub-surface data, 2D and 3D seismic data is utilized to identify low-risk development wells in the existing pools and medium-risk step-out wells that create development opportunities the following drilling season. The majority of the drilling and rework activity occurs in the winter months, usually the end of December through the middle of March, due to local surface conditions. At Fontas, Delphi has a 20 percent working interest in a contiguous land base in excess of 160,000 acres, the gathering system, and a 40 mmcf/d processing facility. The Fontas gas plant is tied into the Nova pipeline system.

During the winter of 2004/2005, Delphi participated in drilling 15 wells in Fontas. Eight of these wells have been successfully completed as gas wells and tied-in, six wells were suspended pending further review and one well was abandoned. Delphi also participated in numerous well workovers, reactivations, pipeline projects and facility modifications which at the end of the drilling season had increased the Company's net production to approximately 725 boe/d. This level of activity is typical of a winter program and results in a capital commitment to Delphi of approximately $4.2 million. Although Fontas is not considered a "growth" property, the consistency and predictability of the yearly development programs, coupled with the high operating netbacks associated with a company owned facility, make this a very desirable property from a cash flow perspective.

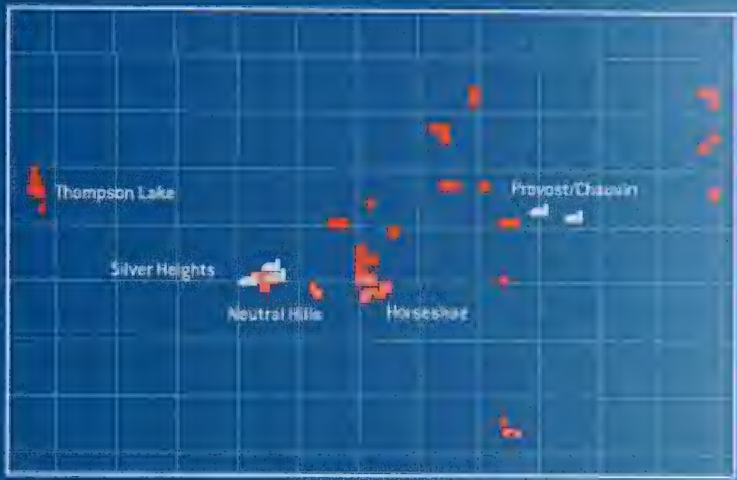
The Company's winter 2005/2006 capital program is nearing completion, including drilling 13 wells and performing several well workovers/reactivations typical of a Fontas winter program. To date, all the new drills have been cased and completed with tie-in operations expected to be finished early in the second quarter. Based on preliminary results, the Company anticipates similar production performance as experienced in previous years, which would result in a peak net production rate in April 2006 of 700 to 750 boe/d.

GRANDE PRAIRIE (DEVELOPMENT JOINT VENTURE)

The Grande Prairie assets are primarily the result of a joint venture agreement with a senior industry producer in which Delphi had the opportunity to reactivate 26 standing wellbores in the greater Grande Prairie area. The terms of the joint venture called for Delphi to pay 100 percent of the reactivation costs with the senior producer having the right to elect to convert to a 50 percent interest or maintain a gross overriding royalty.

During 2005, Delphi initiated production from four wells in the area with a productive capacity of 160 boe/d net. Of the remaining wells, one well is awaiting tie-in, two are being evaluated, two are scheduled for abandonment, five have been abandoned and 12 wells were returned to the joint venture partner with minimal cost to Delphi. In addition to production gains, Delphi has earned a working interest in approximately 3,800 net acres of land.

The Company has an average working interest of 87 percent in the producing properties and a large undeveloped land position of approximately 7,500 net acres.



EAST CENTRAL

east central alberta

The Cretaceous wells typically have initial production rates of one to five mmcf/d and reserves on the order of five to eight bcf/well, while the Devonian Nisku have potential of 15 to 25 bcf/well with typical initial production rates of 10 mmcf/d.

EAST CENTRAL ALBERTA

East Central Alberta currently produces approximately 690 boe/d net to Delphi, consisting of 80 percent oil and 20 percent natural gas. The Company has an average working interest of 87 percent in the producing properties and a large undeveloped land position of approximately 7,500 net acres. On these lands the Company has identified numerous infill and step-out drilling locations primarily on four key properties: Thompson Lake, Neutral Hills, Horseshoe and Chauvin.

During 2005 the Company incurred capital expenditures of approximately $5.0 million on drilling, reactivations and facility optimizations. Although it is difficult to generate growth with such a modest level of capital expenditures, the Company was able to minimize production declines. Although there are an abundance of low-cost opportunities on the East Central Alberta properties, they will have to compete with opportunities in North West Alberta and North East British Columbia which typically have better economic metrics.

EXPLORATION

Delphi's 2005 exploration program has primarily been dedicated to fulfilling a four-well joint venture agreement with a senior industry producer in North West Alberta and North East British Columbia. As part of the agreement, Delphi agreed to pay 100 percent of initial drilling and completion or abandonment costs to earn a 60 percent working interest in each of the prospects. All of the prospects are fully defined on the senior producer's extensive 3D seismic data and the agreement provides the Company access to the partner's pipeline and processing infrastructure. The targets of this exploration joint venture range in age from the Cretaceous Cadomin to the Devonian Nisku. The Cretaceous wells typically have initial production rates of one to five mmcf/d and reserves on the order of five to eight bcf/well, while the Devonian Nisku have potential of 15 to 25 bcf/well with typical initial production rates of 10 mmcf/d. The Company has sold down a portion of its working interest in these wells to achieve a balanced portfolio of development and exploration prospects.

Three of the exploration prospects have been drilled and the fourth is currently drilling. The first prospect was a Devonian test which was drilled and abandoned. The second prospect was the Devonian Wabamun test that has been successfully tested in the primary target interval at rates in excess of eight mmcf/d. Delphi has an 18 percent interest in this well and expects production from the well in the second quarter. In addition to the primary interval, there were numerous uphole sands that appear prospective, based on mud and electric logs. A program is being generated to evaluate these intervals. The third prospect was a Cretaceous Cadomin test that proved to be non-economic in the primary target interval. However, two Upper Cretaceous sands were completed and tested at a combined rate in excess of 1,000 mcf/d. Delphi has a 60 percent interest in this well and tie-in options are being evaluated. Total expenditures on these prospects during 2005 were approximately $3.8 million.

The fourth prospect was spud after January 1 and is expected to reach total depth during the first quarter of 2006.

91%

drilling success

our operational statistics

Reserves

In a report dated March 13, 2006, GLJ Petroleum Consultants Ltd. (GLJ), the Company's independent petroleum engineering firm, evaluated the crude oil, natural gas and natural gas liquids reserves of the Company as at December 31, 2005. GLJ based their evaluation on land data, well and geological information, reservoir studies, estimates of on-stream dates, contract information, forecast commodity prices, operating cost data, capital budgets and future operating plans provided by the Company and prepared a reserves report in accordance with NI 51-101. The Audit and Reserves Committee, with the mandate of reviewing the independent engineering report, has recommended the acceptance of the GLJ reserve estimates for purposes of the Annual Report. The GLJ report has been approved by the Board of Directors.

Reserves Reconciliation

The reconciliation of the Company's proved, probable and proved plus probable reserves for December 31, 2005 is as follows:

Reconciliation of Company Gross Reserves (1)

	Crude oil and NGL (mbbls)			Natural gas (mmcf)			Mboe (6:1)		
	Proved	Probable	Total	Proved	Probable	Total	Proved	Probable	Total
December 31, 2004	1,748	1,051	2,799	30,076	12,886	42,962	6,761	3,199	9,960
Discoveries and extensions	523	27	551	14,385	2,747	17,132	2,921	485	3,406
Technical revisions	(336)	(227)	(564)	2,374	(134)	2,240	58	(250)	(192)
Dispositions	(74)	(68)	(143)	(2,499)	(1,563)	(4,062)	(491)	(329)	(820)
Acquisitions	450	151	602	13,569	4,485	18,054	2,712	899	3,611
	2,311	934	3,245	57,905	18,421	76,326	11,961	4,004	15,965
Production	(334)	–	(334)	(7,245)	–	(7,245)	(1,541)	–	(1,541)
December 31, 2005	1,977	934	2,911	50,660	18,421	69,081	10,420	4,004	14,424

(1) Gross reserves represent the Company's interest before deducting royalties and including any royalty interest of the Company.

Summary of Reserves

The following table outlines the oil, natural gas liquids and natural gas reserves of the Company by product type on a Company interest (before royalties) basis. Proved producing reserves increased 65 percent as compared to 2004 and proved plus probable reserves increased by 45 percent. Proved plus probable natural gas reserves increased 61 percent compared to the previous year.

Company Gross Reserves (1)	**2005**	**2004**	**% change**
Proved producing oil & NGLs (mbbls)	1,516	1,259	20
Proved producing natural gas (mmcf)	41,446	23,034	80
Total proved producing (mboe)	**8,424**	**5,098**	**65**
Proved oil & NGLs (mbbls)	1,977	1,748	13
Proved natural gas (mmcf)	50,660	30,076	68
Total proved (mboe)	**10,420**	**6,761**	**54**
Probable oil & NGLs (mbbls)	934	1,051	(11)
Probable natural gas (mmcf)	18,421	12,886	43
Total probable (mboe)	**4,004**	**3,199**	**25**
Proved plus probable oil & NGLs (mbbls)	2,911	2,799	4
Proved plus probable natural gas (mmcf)	69,081	42,962	61
Total proved plus probable (mboe)	**14,424**	**9,960**	**45**

(1) Gross reserves represent the Company's interest before deducting royalties and including any royalty interest of the Company.

Escalated Pricing Assumptions

The following table sets forth GLJ's pricing, currency exchange rate and inflation rate used in the preparation of the GLJ reserve estimates.

Pricing assumptions	West Texas Intermediate (US$/bbl)	Edmonton Light (CDN$/bbl)	AECO Spot (CDN$/mmbtu)	Exchange rate (US$/CDN$)	Inflation (%)
2006	57.00	66.25	10.60	0.85	2.0
2007	55.00	64.00	9.25	0.85	2.0
2008	51.00	59.25	8.00	0.85	2.0
2009	48.00	55.75	7.50	0.85	2.0
2010	46.50	54.00	7.20	0.85	2.0
2011	45.00	52.25	6.90	0.85	2.0
2012	45.00	52.25	6.90	0.85	2.0
2013	46.00	53.25	7.05	0.85	2.0
2014	46.75	54.25	7.20	0.85	2.0
2015	47.75	55.50	7.40	0.85	2.0
2016	48.75	56.50	7.55	0.85	2.0
Thereafter (1)					

(1) Percentage change of 2.00% represents the change in future prices each year after 2016 to the end of the reserve life.

Net Present Value of Reserves – Escalated Pricing (1) (2)

The net present values of future net revenue of the Company's reserves at various discount rates on a before income tax basis are outlined below.

(000's)	Undiscounted	Discounted at 8%	Discounted at 10%
Proved			
Developed producing	228,280	181,634	173,251
Developed non-producing	33,934	25,667	24,192
Undeveloped	7,704	4,415	3,871
Total proved	**269,918**	**211,716**	**201,314**
Probable	85,785	50,362	45,162
Total proved plus probable	**355,703**	**262,078**	**246,476**

(1) Includes ARTC and before income taxes

(2) As required by NI 51-101, undiscounted well abandonment of $5.1 million, 8 percent discounted of $2.9 million and 10 percent discounted of $2.6 million for total proved and $6.0 million, $3.0 million and $2.6 million respectively, for total proved plus probable reserves are included in net present value determination.

Net Present Value of Reserves – Constant Pricing (1) (2) (3)

The net present values of future net revenue of the Company's reserves at various discount rates on a before income tax basis using constant prices are outlined below.

(000's)	Undiscounted	Discounted at 8%	Discounted at 10%
Proved			
Developed producing	278,567	208,195	196,095
Developed non-producing	41,593	30,173	28,187
Undeveloped	11,609	6,657	5,851
Total proved	**331,769**	**245,025**	**230,133**
Probable	115,624	65,491	58,280
Total proved plus probable	**447,393**	**310,516**	**288,413**

(1) Includes ARTC and before income taxes

(2) As required by NI 51-101, undiscounted well abandonment of $4.4 million, 8 percent discounted of $2.6 million and 10 percent discounted of $2.3 million for total proved and $4.9 million, $2.6 million and $2.3 million respectively, for total proved plus probable reserves are included in net present value determination.

(3) Price assumptions: CDN $68.27/bbl Edmonton Reference Price and CDN $9.71/mmbtu AECO spot.

Finding and Development Costs

The Company has presented its finding and development costs in accordance with NI 51-101. The Company has also calculated finding and development costs including acquisitions and dispositions.

	2005	2004
Capital invested ($000's)		
Land and seismic	345	1,450
Drilling and completion	37,187	20,902
Other	1,364	2,093
Facilities	22,299	13,871
	61,195	38,316
Change in future development costs		
Proved reserves	1,910	4,437
	63,105	42,753
Probable reserves	(1,248)	11,786
Total on-stream costs	61,857	54,539
Acquisitions	51,273	47,391
Dispositions	(5,862)	–
Total capital invested	107,268	101,930
Reserve discoveries, extensions and revisions		
Proved (mboe)	2,979	809
Proved plus probable reserves (mboe)	3,214	995
Reserve net additions (1)		
Proved (mboe)	5,200	4,189
Proved plus probable reserves (mboe)	6,005	6,104
Finding and development costs ($/boe) (2)		
On-stream costs excluding future development costs		
Proved	20.54	47.36
Proved plus probable reserves	19.04	38.51
On-stream costs including future development costs		
Proved	21.18	52.85
Proved plus probable reserves	19.25	54.81
Total capital invested		
Proved	20.87	21.52
Proved plus probable reserves	17.86	16.70

(1) Includes discoveries, extensions, revisions, acquisitions and dispositions.
(2) The aggregate of the exploration and development costs incurred in the most recent financial year, included in capital invested, and the change in estimated future development costs, generally will not reflect total finding and development costs related to reserve additions for that year.

Reserve Life Index

The reserve life index of Delphi has been calculated by using average 2005 production of 4,221 boe/d. The reserve life index is greater than nine years on a proved plus probable basis.

	Crude Oil and NGL (mbbls)			Natural Gas (mmcf)			Mboe (6:1)		
2005	**Proved**	**Probable**	**Total**	**Proved**	**Probable**	**Total**	**Proved**	**Probable**	**Total**
Reserves - December 31, 2005	1,977	934	2,911	50,660	18,421	69,081	10,420	4,004	14,424
Production	334		334	7,245		7,245	1,541		1,541
Reserves life index (years)	5.9		8.7	7.0		9.5	6.8		9.4

Reserves Per Outstanding Common Share

The reserves per 1,000 common shares of the Company was 261 compared to 265 in the previous year.

	2005	2004	% Change
Proved and probable reserves (mboe)	14,424	9,960	45
Proved and probable boe reserves per 1,000 outstanding common share (1)	261	265	(1)

(1) 2004 calculation does not include subscription receipts of 10,169,494 issued for the Bigstone, Alberta acquisition which closed on February 1, 2005

Acreage Summary

The Company's total and undeveloped landholdings by geographic focus area as at December 31, 2005 are outlined below.

	Total		Undeveloped		Fair market
December 31, 2005 (acres)	**Gross**	**Net**	**Gross**	**Net**	**value** (1)
Northwest Alberta	320,320	70,766	169,440	24,863	$4,261,582
Northeast British Columbia	151,231	34,516	89,931	19,513	2,195,903
East Central Alberta	44,005	22,504	13,120	7,460	1,145,554
Total	**515,556**	**127,786**	**272,491**	**51,836**	**$7,603,039**

(1) Seaton Jordon & Associates Ltd. – Undeveloped lands only

The Company is also involved in various farm-in or joint venture arrangements in which capital expenditures must be incurred before earning a working interest in the lands. Total land under these arrangements is over 150,000 gross acres with the potential to earn an average 50 percent working interest.

Recycle Ratio

The recycle ratio is a measure of the effectiveness of the Company's re-investment program. The recycle ratio is a key indicator in the oil and gas industry of efficiency and profitability and is calculated by dividing the finding and development costs for total capital invested into the Company's operating netback.

Year ended December 31 ($/boe)	**2005**	**2004**
Operating netback	30.24	23.58
Proved reserves F&D costs	20.87	21.52
Proved recycle ratio	1.4	1.1
Proved plus probable reserves F&D costs	17.86	16.70
Proved plus probable recycle ratio	1.7	1.4

Net Asset Value

The net asset value of the Company for December 31, 2005 and 2004 are summarized below.

($000's except per share data)	**2005**	**2004** (1)
Estimated net future revenues of proved plus probable reserves discounted at 8%	262,078	106,610
Value of undeveloped land	7,603	8,405
Bank debt plus working capital (2)	(60,375)	(61,274)
Net asset value	209,306	53,746
Common shares outstanding	55,253	37,534
Net asset value per share	3.79	1.36

(1) 2004 calculation does not include subscription receipts of 10,169,494 issued for the Bigstone, Alberta acquisition which closed on February 1, 2005.
(2) 2005 calculation excludes unrealized risk management liability of $645,000.

management's discussion and analysis

(all tabular amounts are expressed in thousands of CDN dollars, except per unit amounts)

- Average production for 2005 increased 147 percent to 4,221 boe/d, as compared to 2004.
- Cash flow for 2005 was $40.2 million ($0.80 per share), increasing 232 percent over the prior year.
- Net earnings were $6.7 million (0.13 per share) compared to $2.0 million ($0.07 per share) for the prior year.
- Net capital expenditures in 2005 of $106.6 million resulted in a net 6.0 million boe of proved plus probable reserves additions at $17.86/boe.
- In February of 2005, Delphi closed the acquisition of liquids-rich natural gas properties at Bigstone, Alberta.

The following discussion and analysis has been prepared by management and reviewed and approved by the Board of Directors of Delphi Energy Corp ("Delphi" or the "Company"). The discussion and analysis is a review of the financial results of the Company based upon accounting principles generally accepted in Canada. Its focus is primarily a comparison of the financial performance for the three and 12 months ended December 31, 2005 and 2004 and should be read in conjunction with the audited financial statements and accompanying notes for the year ended December 31, 2005. The discussion and analysis has been prepared as of March 13, 2006.

Non-GAAP Measures. *For the purpose of reporting production information, reserves and calculating unit prices and costs, natural gas volumes have been converted to a barrel of oil equivalent (boe) using 6,000 cubic feet equal to one barrel. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms with the Canadian Securities Administrators' National Instrument 51-101 when boes are disclosed. Boes may be misleading, particularly if used in isolation.*

Funds from operations and funds from operations per share are not a recognized measure under Canadian generally accepted accounting principles. Management uses funds from operations to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and to repay debt. Funds from operations has been defined by the Company as net earnings plus the addback of non-cash items (depletion, depreciation and accretion, stock based compensation, future income taxes and unrealized (gain)/loss on risk management activities) and excludes the change in non-cash working capital related to operating activities and expenditures on site restoration and reclamation. The Company also presents funds from operations per share whereby amounts per share are calculated using weighted average shares outstanding consistent with the calculation of earnings per share. Delphi's determination of funds from operations may not be comparable to that reported by other companies nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian generally accepted accounting principles. Throughout this discussion, the term cash flow may be used to describe funds from operations.

Forward-looking Statements. *Certain information regarding Delphi set forth in this document, including management's assessment of the Company's future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond the Company's control, including the effects of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other oil and gas companies, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from both internal and external sources. The Company's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements, and accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur.*

PRODUCTION

	Three months ended December 31			Twelve months ended Dece[illegible]		
	2005	2004	% Change	**2005**	2004	[illegible]
Natural gas (mcf/d)	**22,909**	6,849	234%	**19,848**	5,822	[illegible]
Crude oil (bbl/d)	**573**	855	(33%)	**614**	693	[illegible]
Natural gas liquids (bbl/d)	**455**	48	848%	**299**	43	[illegible]
Total (boe/d)	**4,846**	2,045	137%	**4,221**	1,706	[illegible]

Production for the 12 months ended December 31, 2005 averaged 4,221 boe/d representing an increase of 147 percent ove[illegible] year. The significant increase is due to the corporate acquisition of Tercero Energy Inc. (Tercero) at the end of 2004, the acquisi[illegible] liquids-rich natural gas property at Bigstone, Alberta during the first quarter and a very successful drilling program primarily [illegible] half of 2005. Fourth quarter production increased 694 boe/d or 17 percent from the third quarter of 2005. Despite unusually [illegible] conditions in the spring delaying the start of the summer drilling program and unseasonably warm weather in the fourth [illegible] still managed to exit the year at approximately 5,500 boe/d, less than the target of 5,800 to 6,000 boe/d. Delphi is fo[illegible] production to average approximately 7,000 boe/d with an exit rate of 7,800 to 8,300 boe/d.

Natural gas production increased 241 percent on a year over year basis. The increase is due to production from North East [illegible] associated with the Tercero acquisition and the Bigstone property acquisition and subsequent exploitation. Delphi has [illegible] (15.5 net) wells at Bigstone increasing natural gas production from 5,700 mcf/d at the time of acquisition to averaging [illegible] 11,000 mcf/d during the fourth quarter of 2005. The drilling and optimization success at Bigstone is the primary driver of [illegible] production increasing by 3,329 mcf/d or 17 percent from the third quarter of 2005. The success at Bigstone demonstrates [illegible] to acquire high quality assets and add value through optimization and exploitation.

Crude oil production was 11 percent lower during 2005 as compared to 2004. Delphi's objective is to allocate capital to the areas [illegible] projects with the highest return on capital and focus resources on growing natural gas production in North East British Columbia and North West Alberta. As such, Delphi optimized its East Central assets with the objective of maintaining production with minimal capital investment.

Natural gas liquids (NGL) production, primarily condensate, has increased significantly as a result of the high yield of liquids associated with the increased natural gas production at Bigstone, Alberta. At the time of acquisition, the Bigstone property was producing approximately 200 bbls/d of natural gas liquids, whereas in the fourth quarter of 2005 NGL production had increased to 423 bbls/d, a 111 percent increase from acquisition and a 54 percent increase from the third quarter of 2005.

COMMODITY PRICES AND RISK MANAGEMENT

BENCHMARK PRICES

	Three months ended December 31			Twelve months ended December 31		
	2005	2004	% Change	**2005**	2004	% Change
Natural gas						
NYMEX (US $/mmbtu)	**12.36**	6.87	80%	**8.89**	6.18	44%
AECO (CDN $/mcf)	**11.61**	6.74	72%	**8.81**	6.56	34%
Crude oil						
West Texas Intermediate (US $/bbl)	**60.05**	48.28	24%	**56.70**	41.40	37%
Edmonton Light (CDN $/bbl)	**72.11**	57.71	25%	**69.82**	52.69	33%
Foreign exchange rate						
Canadian to US dollar	**1.1737**	1.2207	(4%)	**1.2107**	1.3015	(7%)
US to Canadian dollar	**0.8520**	0.8192	4%	**0.8260**	0.7683	8%

NATURAL GAS

United States natural gas prices are commonly referenced to the New York Mercantile Exchange Henry Hub in Louisiana (NYMEX) while Canadian natural gas prices are typically referenced to the AECO Hub in Alberta. Natural gas prices are influenced more by North American supply and demand than global fundamentals. Record natural gas prices during 2005, particularly in the fourth quarter, when AECO natural gas price hit a high of CDN $14.76/mcf in December, were the result of extreme hurricane activity significantly curtailing production in the Gulf of Mexico, extremely warm weather during the summer months pushing cooling demands and hence natural gas fired generation of electricity to record levels and the expectation of a colder than average winter in North America. All of these factors supported the expectation that the demand for natural gas would exceed the supply.

Subsequent to year end, the colder than expected winter has not materialized and in fact a warmer than average winter has existed throughout most of North America, including the top natural gas consuming regions in Canada and the United States. Delphi expects prices to remain volatile throughout 2006 and as such, has extended its price protection strategy.

CRUDE OIL

West Texas Intermediate at Cushing, Oklahoma (WTI) is the benchmark reference for North American crude oil prices. Canadian crude oil prices are based upon postings, primarily at Edmonton, Alberta, and represent the WTI price adjusted for quality and transportation differentials as well as the US/CDN dollar exchange rate. Crude oil prices continued to show sustained strength during 2005 and in the fourth quarter due to strong global demand and geopolitical unrest in major oil producing countries. During the three and 12 months ended December 31, 2005, Canadian crude oil prices were negatively affected as a result of the strengthening Canadian dollar relative to its U.S. counterpart.

The prices received for crude oil are related to the price of crude oil in world markets. Prices for heavy oil and other lesser quality crudes trade at a discount or differential to light crude oil due to the additional processing costs. Heavy oil differentials widened from CDN $20.70/bbl during the third quarter of 2005 to CDN $28.64/bbl in the fourth quarter with an average differential of CDN $24.17 during 2005. The wide differential has been mainly due to an increase in heavy and medium grade sour crude types entering the North American market and a lack of refining capacity to process this heavier quality crude.

RISK MANAGEMENT ACTIVITIES

Delphi enters into both financial and physical commodity contracts as part of its risk management program to manage commodity price fluctuations designed to ensure sufficient cash is generated to fund its capital program.

The Company has chosen to mark-to-market its outstanding financial fixed price contracts and record any unrealized gain or loss. The estimated fair value of unrealized derivative instruments is reported on the balance sheet with any change in the unrealized positions charged to earnings. The fair values of these instruments are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the instruments outstanding at December 31, 2005 with reference to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, actual amounts realized may differ from these estimates. During the three and 12 month period ended December 31, 2005, Delphi recorded a realized loss on financial commodity contracts of $1.4 million and $2.9 million respectively. The Company incurred an unrealized non-cash gain on risk management activities for the three months ended December 31, 2005 of $2.6 million and an unrealized non-cash loss of $0.6 million for the year ended December 31, 2005.

The Company has fixed the price applicable to future production through the following contracts:

Time period	Commodity	Type of contract	Quantity contracted	Canadian price (CDN$/GJ)
November 2005 – March 2006	Natural gas	Financial	2,000 GJ/d	$7.79 fixed
November 2005 – March 2006	Natural gas	Physical	2,000 GJ/d	$8.00 floor/$8.90 ceiling
November 2005 – March 2006	Natural gas	Physical	2,000 GJ/d	$7.50 floor/$9.65 ceiling
November 2005 – March 2006	Natural gas	Physical	1,000 GJ/d	$11.00 floor/$13.40 ceiling
November 2005 – March 2006	Natural gas	Physical	1,000 GJ/d	$12.66 floor/$14.15 ceiling (1)
April 2006 – October 2006	Natural gas	Physical	2,000 GJ/d	$9.50 floor/$10.90 ceiling
April 2006 – October 2006	Natural gas	Physical	2,000 GJ/d	$9.19 fixed
April 2006 – October 2006	Natural gas	Physical	2,000 GJ/d	$10.50 floor/$11.15 ceiling
April 2006 – October 2006	Natural gas	Physical	1,000 GJ/d	$8.32 fixed (2)
April 2006 – October 2006	Natural gas	Physical	2,000 GJ/d	$8.00 floor/$8.60 ceiling (2)
November 2006 – March 2007	Natural gas	Physical	2,000 GJ/d	$10.00 fixed (2)
November 2006 – March 2007	Natural gas	Physical	4,000 GJ/d	$9.50 floor/$10.65 ceiling (2)
November 2006 – March 2007	Natural gas	Physical	2,000 GJ/d	$9.50 floor/$11.35 ceiling (2)

(1) Converted at December 31, 2005 foreign exchange rate of US/CDN $0.86
(2) Contracts entered into subsequent to year end

The contract price on physical contracts is recognized in earnings in the same period as the production revenue.

REALIZED SALES PRICES

	Three months ended December 31			Twelve months ended [illegible]		
	2005	2004	% Change	**2005**	2004	[illegible]
Natural gas ($/mcf)	**12.17**	7.02	73%	**9.37**	6.74	[illegible]
Loss on financial contracts ($/mcf)	**(0.48)**	–	–	**(0.17)**	–	[illegible]
Realized gas price ($/mcf)	**11.69**	7.02	67%	**9.20**	6.74	[illegible]
Crude oil ($/bbl)	**43.49**	35.99	21%	**45.48**	37.58	[illegible]
Loss on financial contracts ($/bbl)	**(7.85)**	–	–	**(7.10)**	–	[illegible]
Realized oil price ($/bbl)	**35.64**	35.99	(1%)	**38.38**	37.58	[illegible]
Natural gas liquids ($/bbl)	**58.35**	46.65	25%	**51.82**	41.7[illegible]	[illegible]
Total realized sales price ($/boe)	**64.94**	39.66	64%	**52.48**	39.19	[illegible]

The increase in the average price received by Delphi during the three and 12 months ended December 31, 2005, is con[illegible] upward trend of the benchmark WTI over the same period offset by the strengthening of the Canadian dollar and wide[illegible] differentials. Delphi's oil production is predominantly a medium grade oil therefore the Company's average price als[illegible] quality differential. The Company continues to receive higher than the AECO spot price on natural gas sales due to the hi[illegible] of natural gas production and the sale of approximately 18 percent of the Company's production being priced at Chicago [illegible] Alliance Pipeline for the quarter ended December 31, 2005 and 21 percent for the year ended December 31, 2005. During [illegible] of 2005, Delphi benefited from an above average basis differential between the Chicago price and AECO price for produc[illegible] on the Alliance Pipeline to the United States. Realized natural gas liquids prices have increased significantly due to the [illegible] received for condensate, the primary component of the Company's natural gas liquids production.

REVENUE

	Three months ended December 31			Twelve months ended December 31		
	2005	2004	% Change	**2005**	2004	% Change
Natural gas	**25,652**	4,422	480%	**67,898**	14,314	374%
Crude oil	**2,293**	2,831	(19%)	**10,209**	9,505	7%
Natural gas liquids	**2,447**	206	1,088%	**5,657**	655	764%
Realized loss on financial contracts	**(1,431)**	–	–	**(2,884)**	–	–
Total	**28,961**	7,459	288%	**80,880**	24,474	230%

The increase in revenue is attributable to increased production volumes from the acquisition of Tercero and the natural gas and natural gas liquids producing property in Bigstone, a successful drilling program and increased commodity prices. Revenue during the fourth quarter of 2005 increased $8.3 million or 41 percent from the third quarter due to a 17 percent increase in production and a 20 percent increase in the realized price received. Revenue for the year ended December 31, 2005 increased 230 percent due to a 34 percent increase in the Company's average realized sales price and a 147 percent increase in production. Of the increase in total revenue, 95 percent is attributable to natural gas sales revenue which increased 374 percent over 2004.

ROYALTIES

	Three months ended December 31			Twelve months ended December 31		
	2005	2004	% Change	**2005**	2004	% Change
Crown	**6,929**	1,040	566%	**17,314**	3,407	408%
Freehold and gross overriding	**247**	345	(28%)	**1,131**	943	20%
Total	**7,176**	1,385	418%	**18,445**	4,350	324%
Royalty credits	**(630)**	(491)	28%	**(2,110)**	(1,691)	25%
Net	**6,546**	894	632%	**16,335**	2,659	514%
Per boe	**14.68**	4.75	209%	**10.60**	4.26	149%
Percent of total revenue	**22.6%**	12.0%		**20.2%**	10.9%	

The Company pays royalties to provincial governments (Crown), freeholders, which can be individuals or companies, and other oil and gas operators, who own surface or mineral rights. Crown royalty rates are calculated on a sliding scale based on commodity prices and individual well production rates. Royalty rates can change due to price fluctuations or changes in production volumes on a well by well basis subject to a minimum and maximum rate restriction ascribed by the Crown. During the year ended December 31, 2005, royalties as a percentage

of revenue increased significantly due to the Company's production switching from low producing oil wells which have royalty rates of zero to 15 percent based on volume and prices to more prolific natural gas wells associated with the Tercero and Bigstone acquisitions that typically have royalty rates of 15 to 25 percent. During the fourth quarter of 2005, royalties as a percentage of revenue increased to 22.6 percent from 18.0 percent in the third quarter due to higher volumes at Bigstone and a higher royalty rate on NGL volumes of approximately 32 percent. Delphi is expecting royalties as a percentage of revenue to average between 21 to 23 percent for 2006.

Royalty credits for the year ended December 31, 2005 are higher versus the comparative period due to the acquisition of the Bigstone property and capital being spent on natural gas infrastructure which has resulted in an increase to the Gas Cost Allowance (GCA) credit. The GCA is a deduction from Alberta Crown royalties to compensate the Company for the cost of gathering, processing and compression facilities to process the Crown royalty portion of production. The Company receives the Alberta Royalty Tax Credit (ARTC), a tax rebate from the Alberta government for eligible crown royalties paid in the year subject to a maximum of $0.5 million in 2005.

OPERATING EXPENSES

	Three months ended December 31			Twelve months ended December 31		
	2005	2004	% Change	**2005**	2004	% Change
Total	**3,523**	2,139	65%	**13,041**	5,915	120%
Per boe	**7.90**	11.37	(31%)	**8.46**	9.47	(11%)

Operating expenses on a per boe basis for the three and 12 months ended December 31, 2005 decreased 31 percent and 11 percent over the comparative prior periods, respectively. This reduction was achieved despite an environment which faces strong inflationary pressure as a result of the high level of industry activity creating tight service markets and significantly higher prices for fuel and power costs required for much of the Company's oil production. The decrease is consistent with Delphi's expectation due to the significant production growth in Delphi's low cost natural gas producing properties. Delphi's growth platform is predominantly focused on lower operating cost natural gas opportunities in North West Alberta and North East British Columbia, therefore, operating costs are expected to remain static for the first quarter of 2006 and trend downward during the remainder of 2006 as production from Bigfoot and other natural gas properties are brought on-stream.

TRANSPORTATION EXPENSES

	Three months ended December 31			Twelve months ended December 31		
	2005	2004	% Change	**2005**	2004	% Change
Total	**1,418**	493	188%	**4,893**	1,173	317%
Per boe	**3.18**	2.62	21%	**3.18**	1.88	69%

On a per boe basis, transportation costs for the 12 months ended December 31, 2005 increased 69 percent over 2004 primarily due to the transportation costs associated with natural gas production in North East British Columbia and the natural gas production from the Bigstone area. Transportation costs on a per boe basis during the fourth quarter of 2005 were consistent with the third quarter of 2005. The Company expects a marginal increase in transportation costs on a per boe basis for 2006 as more production from North East British Columbia including Bigfoot is brought on production.

In British Columbia, infrastructure is owned by Duke Energy that enables natural gas producers to avoid facility construction in exchange for regulated gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

Approximately 39 percent in the fourth quarter of 2005 and 55 percent in the 12 months ended December 31, 2005 of the Company's natural gas production from the Bigstone area was shipped on the Alliance Pipeline and sold in Chicago. The costs of transmission from the field to Chicago are included in transportation expenses.

GENERAL AND ADMINISTRATIVE

	Three months ended December 31			Twelve months ended December 31		
	2005	2004	% Change	**2005**	2004	% Change
General and administrative costs	**1,252**	875	43%	**4,666**	2,874	62%
Overhead recoveries	**(434)**	(185)	135%	**(869)**	(741)	17%
Salary allocations	**(395)**	(126)	213%	**(1,306)**	(546)	139%
Net	**423**	564	(25%)	**2,491**	1,587	57%
Per boe	**0.95**	3.00	(68%)	**1.62**	2.54	(36%)

On a per boe basis, general and administrative (G&A) costs for the three and 12 months ended December 31, percent and 36 percent over the comparable period in 2004. On a gross basis for the year ended December 31, 200 57 percent commensurate with increased staffing and activity levels. Due to unprecedented levels of activity for the industry as a whole in 2005, the costs associated with hiring, compensating and retaining employees and consulta and are expected to continue to rise going forward. In order for the Company to have continued success it is para retain its current staff and have the ability to continue to attract highly qualified professionals as needed. Delphi a G&A during 2006 but decreasing G&A per boe compared to the year ended December 31, 2005.

Salary allocations have increased by 213 percent and 139 percent due to operating oil and gas properties and increas efforts toward the Company's capital program. Overhead recoveries have increased during 2005, particularly dur due to higher capital spending during the year.

STOCK BASED COMPENSATION

	Three months ended December 31			Twelve months en	
	2005	2004	% Change	**2005**	2004
Stock based compensation expense	**382**	341	12%	**1,631**	599
Per boe	**0.86**	1.81	(53%)	**1.06**	0.96

Stock based compensation expense is the amortization over the vesting period of the fair value of stock options g directors and key consultants of the Company. The fair value of all options granted is estimated at the date of grant us option pricing model. The non-cash compensation expense for the year ended December 31, 2005 increased 172 perc options being granted to new staff to facilitate the significant growth of the Company, with one-third of the options pursuant to the Company's stock option plan and a higher average fair value option price. Fourth quarter non-cash compensa on a gross basis is consistent with the third quarter of 2005 with no new options being granted during this period.

INTEREST

	Three months ended December 31			Twelve months ended December 31		
	2005	2004	% Change	**2005**	2004	% Chang
Total	**883**	399	121%	**3,658**	794	361%
Per boe	**1.98**	2.12	(7%)	**2.37**	1.27	86

Interest expense for the year ended December 31, 2005 on a gross and per boe basis has increased commensurate with higher debt levels and $10.0 million mezzanine debt outstanding from December 8, 2004 to February 23, 2005 with an effective of 15.75 percent used to fund the growth in the Company's operations and to finance the significant property acquisition during the quarter of 2005. Interest expense for the fourth quarter is consistent with the third quarter on a gross basis and decreased a per boe basis due to higher production volumes in the quarter.

DEPLETION, DEPRECIATION AND ACCRETION

	Three months ended December 31			Twelve months ended December 31		
	2005	2004	% Change	**2005**	2004	% Change
Depletion and depreciation	**8,329**	3,083	170%	**26,568**	8,688	206
Accretion expense	**166**	124	34%	**526**	315	67%
Total	**8,495**	3,207	165%	**27,094**	9,003	201%
Per boe	**19.05**	17.05	12%	**17.59**	14.42	22%

Depletion, depreciation and accretion per boe increased 12 percent and 22 percent, respectively, for the three and 12 months ended December 31, 2005. This increase is attributable to higher cost proved reserve additions, through drilling and acquisitions, which is a trend throughout the industry. The increase in total depletion and depreciation versus the comparable periods is a result of increased production levels and a higher per boe rate.

Accretion expense of asset retirement obligations relates to the passing of time until the Company estimates it will retire its assets and restore the asset locations to a condition which meets or exceeds environmental standards. Due to the long term nature of certain assets of the Company, this accretion expense is estimated to extend over a term of three to 20 years. The Company uses a credit adjusted risk-free rate of eight percent for the purpose of calculating the fair value of its asset retirement obligations and hence the accretion expense. The accretion expense for the three and 12 months ended December 31, 2005 increased 34 percent and 67 percent over comparable periods. The increase is due to increased drilling and the major acquisitions at the end of 2004 and first quarter of 2005.

TAXES

	Three months ended December 31			Twelve months ended December 31		
	2005	2004	% Change	**2005**	2004	% Change
Capital	**49**	220	(78%)	**250**	221	13%
Future (recovery)	**3,464**	(122)	–	**4,165**	570	631%
Total	**3,513**	98	3,485%	**4,415**	791	458%

Current tax for the three months and 12 months ended December 31, 2005 consists of the Federal Large Corporations Tax (LCT). The increase in current taxes is due to the Company's growth during 2005 resulting in a higher capital base for which LCT is calculated. Future income tax of $3.5 million and $4.2 million was recorded for the three months and 12 months ended December 31, 2005. The effective tax rates for the three and 12 months ended December 31, 2005 were 35.3 percent and 39.8 percent.

FUNDS FROM OPERATIONS

	Three months ended December 31			Twelve months ended December 31		
	2005	2004	% Change	**2005**	2004	% Change
Net earnings (loss)	**6,425**	(678)	–	**6,677**	1,953	242%
Non-cash items						
Depletion, depreciation and accretion	**8,495**	3,207	165%	**27,094**	9,003	201%
Unrealized (gain)/loss on financial contracts	**(2,648)**	–	–	**645**	–	–
Stock based compensation expense	**382**	341	12%	**1,631**	599	172%
Future income taxes	**3,464**	(122)	–	**4,165**	570	631%
Funds from operations	**16,118**	2,748	487%	**40,212**	12,125	232%

For the three and 12 months ended December 31, 2005 funds from operations were $0.31 per basic share (2004 – $0.09) and $0.80 per basic share (2004 – $0.45). The increase in funds from operations per share is a function of higher realized commodity prices and increased production volumes illustrating Delphi's commitment to maximizing shareholder value by making accretive acquisitions and successfully executing the capital program.

NET EARNINGS

For the three and 12 months ended December 31, 2005, Delphi recorded net earnings of $6.4 million (2004 – loss of $0.7 million) and $6.7 million (2004 – $2.0 million), respectively. Earnings were adversely affected by non-cash items such as depletion, depreciation, accretion, unrealized losses on financial contracts, stock based compensation and future income taxes.

NETBACK ANALYSIS

	Three months ended December 31			Twelve months end	
	2005	2004	% Change	**2005**	2004
Barrel of oil equivalent ($/boe)					
Realized sales price	**64.94**	39.66	64%	**52.48**	39.19
Royalties, net of ARTC	**14.68**	4.75	209%	**10.60**	4.7[illegible]
Operating expenses	**7.90**	11.37	(31%)	**8.46**	9.47
Transportation expenses	**3.18**	2.62	21%	**3.18**	1.88
Operating netback	**39.18**	20.92	87%	**30.24**	23.58
G&A	**0.95**	3.00	(68%)	**1.62**	2.54
Interest	**1.98**	2.12	(7%)	**2.37**	1.27
Current taxes	**0.11**	1.17	(91%)	**0.16**	0.36
Cash netback	**36.14**	14.63	147%	**26.09**	[illegible]
Unrealized (gain)/loss on financial contracts	**(5.94)**	–	–	**0.42**	
Stock based compensation expense	**0.86**	1.81	(53%)	**1.06**	0.96
Depletion, depreciation and accretion	**19.05**	17.05	12%	**17.59**	14.42
Future income taxes (recovery)	**7.77**	(0.65)	–	**2.70**	0.91
Net earnings	**14.40**	(3.58)	–	**4.32**	3.1[illegible]

Fourth quarter cash netbacks increased $9.43/boe or 35 percent over the third quarter of 2005 due to a higher reali boe (increased $10.99/boe or 20 percent), lower operating costs per boe (decreased $1.70/boe or 18 percent) [illegible] (decreased $1.06/boe or 53 percent) offset by an increase in royalties per boe (increased $4.70/boe or 47 percent)

DRILLING RESULTS

	Three months ended December 31		Twelve months ended Decem	
	Gross	**Net**	**Gross**	**Net**
Natural gas wells	12.0	10.1	36.0	[illegible]
Oil wells	1.0	1.0	2.0	[illegible]
Dry holes	–	–	7.0	2.[illegible]
Total wells	13.0	11.1	45.0	[illegible]
Success rate (%)	100%	100%	84%	[illegible]

Although slowed by wet weather in the spring and early summer, Delphi was still able to execute the 2005 capital program including [illegible] 13 wells (11.1 net) during the fourth quarter. During the year Delphi drilled 21 gross (15.5 net) wells at Bigstone achieving a 95 [illegible] net success rate with each unsuccessful well being non operated, 17 wells (3.4 net) at Fontas, 3 wells (1.1 net) in North East B[illegible] Columbia and four wells (2.0 net) in North West Alberta. Of the wells drilled in North West Alberta, three were drilled in conjunction [illegible] Exploration Joint Venture resulting in one (0.2 net) dry hole and two (0.8 net) successful wells which are expected to be on produ[illegible] the end of the first quarter of 2006.

CAPITAL INVESTED

	Three months ended December 31			Twelve months ended December 31		
	2005	2004	% Change	**2005**	2004	% Change
Land	**107**	640	(83%)	**242**	1,226	(80%)
Seismic	**17**	22	(23%)	**103**	224	(54%)
Drilling and completions	**19,618**	11,064	77%	**37,187**	20,902	78%
Equipping and facilities	**8,974**	2,177	312%	**22,299**	13,871	61%
Property and corporate acquisition	**(94)**	46,795	–	**51,273**	47,391	8%
Capitalized expenses	**352**	107	229%	**1,187**	534	122%
Other	**82**	1,612	(95%)	**177**	1,559	(89%)
Capital invested	**29,056**	62,417	(53%)	**112,468**	85,707	31%
Asset retirement costs	**1,071**	1,315	(19%)	**2,469**	1,695	46%
Total capital invested	**30,127**	63,732	(53%)	**114,937**	87,402	32%

Delphi's strategy for generating an inventory of prospects is predominantly focused on (a) targeted property or corporate acquisitions, on an exclusive basis, which have significant low-risk development/exploitation opportunities and (b) internally generated joint venture farm-in opportunities. The farm-in opportunities generally involve a component in which Delphi will pay a higher proportion of the initial capital to earn a lesser interest in the lands. On a large scale basis, Delphi prefers this approach to the acquisition of lands at Crown land sales as prices for land have become very competitive. Hence, the probability of acquiring the Crown lands has become significantly reduced and upon acquiring the lands additional seismic is often required before opportunities, if any, are identified. Farm-in opportunities generally come with identified prospects and/or seismic and allow Delphi to employ its capital into the drilling of an opportunity immediately. Delphi still achieves its objective of obtaining lands in areas identified as prospective without the high cost and uncertainty of competitive Crown land sales. Selective Crown land acquisitions are undertaken in the Company's core areas.

The Company allocates approximately 85 to 90 percent of its capital program to development/exploitation opportunities and 10 to 15 percent to higher risk – higher reward exploration opportunities. Delphi generally enters into arrangements for exploration opportunities at a high working interest and subsequently reduces its participation to a risk tolerance level appropriate for the opportunity and capital funding available.

In 2005, Delphi incurred record total capital expenditures of $112.5 million, consisting of the liquids rich natural gas property acquisition at Bigstone, Alberta in February for $51.3 million and capital expenditures of $61.2 million for activity undertaken in the Company's various operating areas. The Company incurred asset retirement costs of $2.5 million associated with obligations for future site restoration and abandonment of facility sites and wells drilled and acquired during the year.

Approximately $37.9 million, 62 percent, of the capital incurred in the field for the year was directed at the optimization of well-site facilities and infill drilling opportunities at Bigstone. At Fontas, Alberta the 2005 winter program in the area consisted of the installation of a refrigeration plant to meet transmission pipeline specifications and the drilling of infill and pool extension opportunities for a total cost of $4.2 million. North East British Columbia expenditures totaled $5.7 million for the year towards drilling several lower working interest wells and facility optimization. In North West Alberta, the Company incurred $4.6 million, a majority of which related to the development joint venture to evaluate and tie-in standing cased wells to earn a working interest or abandon the well. High-impact exploration capital totaled $3.8 million or six percent of field activity resulting in a 66 percent success rate with one exploration well drilling over year end. In 2005, East Central Alberta capital of $5.0 million consisted primarily of maintenance capital and the drilling of one well.

In 2005, Delphi disposed of non-core minor properties in Alberta for total proceeds of $5.9 million.

LIQUIDITY AND CAPITAL RESOURCES

FUNDING

For the three and 12 months ended December 31, 2005 the Company decreased bank debt by $16.6 million and $5.7 million [illegible] utilizing a combination of funds from operations, the issuance of shares and sale of non-core assets.

	Three months ended December 31	Twelve months ended Decem[illegible]
Sources:		
Funds from operations	16,118	40[illegible]
Issue of flow-through common shares	14,003	[illegible]
Issue of common shares	14,000	14,0[illegible]
Exercise of stock options	–	[illegible]
Proceeds on the disposition of properties	–	[illegible]
Cash held in trust	–	[illegible]
Cash on hand	–	[illegible]
Change in non-cash working capital	4,021	[illegible]
	48,142	[illegible]
Uses:		
Share issue costs	1,873	[illegible]
Additions to property, plant and equipment additions	29,056	61,195
Property acquisition	–	51,2[illegible]
Repayment of mezzanine debt	–	10,0[illegible]
Expenditures on site restoration and reclamation	613	61[illegible]
	31,542	125,822
Decrease in bank debt	16,600	5,7[illegible]

SHARE CAPITAL

At December 31, 2005, the Company had 55.3 million shares outstanding (2004 – 47.7 million). During the year the company completed three share issuances:

Date of issue	Shares issued	Price per unit	Gross proceeds	Use of proceeds
March 31, 2005	2.70 million flow-through shares	$4.40	$12.0 million	Reduce financial leverage initially followed by funding the 2005 exploration program
December 13, 2005	1.96 million flow-through shares	$7.15	$14.0 million	Reduce financial leverage initially followed by funding the 2006 exploration program
December 29, 2005	2.50 million common shares	$5.60	$14.0 million	Reduce financial leverage and fund the Company's 2006 capital expenditure program

The common shares of Delphi trade on the TSX under the symbol DEE. The following table summarizes outstanding share data for the three and 12 months ended December 31, 2005.

	Three months ended December 31	Twelve months ended December 31
Weighted average common shares		
Basic	51,233	50,060
Diluted	52,552	50,931
Trading statistics		
High	$ 5.95	$ 5.95
Low	$ 4.84	$ 2.65
Average daily volume	105,690	141,110

As at March 13, 2006, the Company had 55.25 million common shares outstanding and 4.13 million stock options outstanding.

BANK DEBT PLUS WORKING CAPITAL DEFICIT

At December 31, 2005, the Company had $41.7 million outstanding on its credit facility and a working capital deficit of $18.7 million, excluding the accrued liability of $0.6 million relating to the unrealized loss on financial contracts, for total debt plus working capital deficit of $60.4 million, down from $73.0 at the end of the third quarter of 2005. The Company's anticipated funds from operations is expected to be sufficient to meet the current working capital deficit. The capital intensive nature of the industry will generally result in the Company having a working capital deficit. At December 31, 2005, the Company had a credit facility of $82.0 million and a development facility associated with the Bigfoot joint venture for $30.0 million. The credit facility is subject to annual review in April 2006 based upon the Company's December 31, 2005 engineering report adjusted for the lenders' price forecast.

FINANCIAL STRATEGY

Over the past 16 months, Delphi has undertaken two major acquisitions and incurred record capital expenditures in the field. Funding of these types of significant expenditures can be derived from internally generated funds from operations, credit facilities established with the Company's lenders, proceeds from the disposition of non-core properties or the issuance of common shares from treasury. The Company may issue common shares with or without flow-through tax benefits. Flow-through common shares allow the issuer to pass on the tax benefits of qualifying exploration expenditures (100 percent deductible) to the investor. Typically, flow-through shares attract a premium issue price to the then existing market price due to this tax benefit received by the investor. The Company also has an active risk management program to establish minimum price floors for a portion, as high as 50 percent, of its natural gas production thereby removing a degree of risk of commodity price volatility from its internally generated funds from operations.

The funding alternatives chosen by Delphi for its acquisition and capital program are influenced by the capital market environment for equity, interest rate environment for the cost of debt and the nature of the expenditures being incurred. In examining these factors, Delphi considers both the current environment and its expectations of those factors going forward.

Typically, Delphi's share price over the past 18 months has traded at a lower cash flow multiple than its peer group. Consequently, Delphi's cost of capital for equity is higher, which results in greater dilution when equity is issued than if Delphi was receiving a cash flow multiple more consistent with its peer group average. Meanwhile, the interest rate environment has been relatively stable and historically low over the past two years with slight increases more recently but no expectation of dramatic increases. With this combination of lower cost of debt, higher cost of equity from a dilutive perspective and the confidence of capital being incurred on assets with significant short term low-risk development, Delphi has strategically leveraged the balance sheet at the closing of acquisitions over the past 16 months.

Delphi has seen the benefit of using this leverage over the past year as the Company's debt to cash flow ratio was significantly lowered during 2005 from a high of almost 3:1 at the end of the first quarter of 2005 to 0.9:1 at the end of the year based on annualized fourth quarter cash flow. Over that same period of time, Delphi avoided excess dilution by exploiting the assets acquired and issuing common shares at $5.60 per share in December 2005 versus $2.20 and $2.90 per share late in 2004 to close the Tercero and Bigstone acquisitions, respectively.

For 2006, Delphi will have a significant winter capital program in many of its core North West Alberta and North East British Columbia areas. In addition, beginning in 2006, the Company will be incurring significant expenditures on its Bigfoot joint venture in North East British Columbia. Funding of this capital will be derived from internally generated funds from operations with some downside protection through the continuation of the Company's risk management program, the expected disposition of non-core properties in East Central Alberta and use of the Company's credit facilities. The Bigfoot joint venture requires significant capital expenditures during the first two years while Delphi earns its 50 percent working interest in the associated lands. Currently, the Company has secured a $30 million credit facility, $20 million available initially with an additional $10 million available if the program is performing as expected, with its lenders to initially fund a portion of the joint venture. Due to the long term nature of this asset, the Company will be investigating additional funding alternatives which may better match the nature of the financing with the long term nature of the asset.

As a result of Delphi's capital program being heavily weighted to the early part of the year, the debt to cash flow ratio is expected to increase from year end through the first half of 2006. Not unlike 2005, the debt to cash flow ratio will come down by year end as capital expenditures are reduced in the latter half of 2006, while at the same time funds from operations are expected to grow with increased production volumes and continued improvement in operating netbacks.

Delphi is confident its use and timing of leverage in combination with a commodity price risk management program and low-risk development expenditures is a proven strategy to increase shareholder value.

SELECTED QUARTERLY INFORMATION

The following table sets forth certain information of the Company for the past eight consecutive quarters.

	Dec. 31 2005	Sept. 30 2005	Jun. 30 2005	Mar. 31 2005	Dec. 31 2004	Sept. 30 2004	Jun. 30 2004	Mar. 31 [illegible]
Production								
Oil and NGLs (bbl/d)	**1,028**	889	865	872	903	857	[illegible]	[illegible]
Natural gas (mcf/d)	**22,909**	19,580	19,961	16,880	6,849	5,353	5,[illegible]	[illegible]
Barrels of oil equivalent (boe/d)	**4,846**	4,152	4,192	3,685	2,045	1,749	[illegible]	[illegible]
Financial ($000's, except as noted)								
Petroleum and natural gas revenue	**28,961**	20,606	17,335	13,978	7,459	6,233	[illegible]	[illegible]
Funds from operations	**16,118**	10,199	7,937	5,958	2,748	3,557	[illegible]	[illegible]
Per share - basic & diluted	**0.31**	0.20	0.16	0.12	0.09	0.14	[illegible]	[illegible]
Net earnings (loss)	**6,425**	1,190	1,004	(1,942)	(679)	854	[illegible]	[illegible]
Per share - basic	**0.13**	0.02	0.02	(0.04)	(0.02)	0.03	0[illegible]	[illegible]
Per share - diluted	**0.12**	0.02	0.02	(0.04)	(0.02)	0.03	0[illegible]	[illegible]
Capital expenditures	**29,056**	16,280	7,096	60,036	62,417	11,160	[illegible]	[illegible]
Per unit information								
Natural gas ($/mcf)	**11.69**	9.30	7.80	7.28	7.02	6.25	[illegible]	[illegible]
Oil and natural gas liquids ($/bbl)	**45.70**	47.15	40.35	37.16	37.57	40.03	35.[illegible]	[illegible]
Oil equivalent ($/boe)	**64.94**	53.95	45.45	42.13	39.66	38.73	3[illegible]	[illegible]
Operating netback ($/boe)	**39.18**	31.17	24.45	23.83	20.92	23.66	24.[illegible]	[illegible]

CONTRACTUAL OBLIGATIONS

The Company is committed, under contracts of varying lengths, for the utilization of gathering, processing and pipeline capac[illegible] natural gas processing and gathering system in North East British Columbia. The future minimum commitments are as follows:

2006	$	[illegible]
2007		[illegible]
2008		[illegible]
2009		[illegible]
2010		[illegible]
2011 – 2016	$	8,935

On November 23, 2005, the Company announced a farm-in agreement with a major producer to jointly develop a natural gas resource play in the Bigfoot area of North East British Columbia, an opportunity distinct from the Bigstone property in North West Alberta. [illegible] Company will pay 90 percent of the capital expenditures up to $81.0 million to earn a 50 percent working interest on 118 sections ([illegible] acres) from the partner. Pursuant to the agreement, the Company has provided the partner with a $10.0 million deposit towards these expenditures. As at December 31, 2005, Delphi had incurred $0.1 million relating to this commitment.

The Company's lease rental commitment on office premises from 2006 through 2008 is $0.1 million per annum.

As at December 31, 2005, the Company had incurred the necessary qualifying exploration expenditures to satisfy the terms of the flow-through common shares issued during 2004. Although the Company believes it has incurred the necessary qualifying expenditures, these amounts may be subject to audit and subsequent interpretation by the Canada Revenue Agency. The Company has an obligation to incur qualifying exploration expenditures of $26.0 million by December 31, 2006 to satisfy the terms of the flow-through common shares issued during 2005.

GUARANTEES AND OFF-BALANCE SHEET ARRANGEMENTS

Delphi has not entered into any off-balance sheet arrangements or guarantees.

BUSINESS CONDITIONS AND RISK

The business of exploration, development and acquisition of oil and gas reserves involves a number of uncertainties and as a result the Company is exposed to certain business risks inherent in the oil and gas industry which affect results. These business risks can generally be grouped into two major areas: operations, including environmental, and financial.

Operationally, the Company faces risks associated with finding, developing and producing oil and gas reserves. The Company attempts to control operating risks by maintaining a disciplined approach to implementation of the exploration and development program. Exploration risks are managed by hiring experienced technical staff and by concentrating the exploration activity on specific core regions where the Company has experience and expertise. The Company also attempts to operate associated projects where its level of ownership is sufficient. Operational control allows the Company to manage costs, timing and sales of production.

Estimates of economically recoverable reserves and the future net cash flow they will generate are based on a number of factors and assumptions, such as commodity prices, projected production and future capital and operating costs. All of these estimates may vary from actual results. The Company has its reserves evaluated annually by an independent engineering firm and reviews their findings with the Audit Committee of the Board of Directors.

Environmental risks are also associated with field operations. The Company has health and safety programs and procedures and an environmental standards policy. These policies and procedures are designed to protect and maintain the environment with respect to all Company operations. The Company performs an annual third party audit of the safety and environmental policies designed to ensure compliance. Delphi also carries environmental liability, property, drilling and general liability insurance.

The Company is also exposed to financial risks in the form of commodity prices, interest rates, the Canadian to U.S. dollar exchange rate and inflation. Delphi manages commodity price risks by focusing its capital program on areas that are expected to generate attractive rates of return even at substantially lower commodity prices than the industry is currently receiving. The Company also conducts a commodity price risk management program designed to mitigate large downward movements in commodity prices.

See the Company's 2006 Annual Information Form (AIF) for a further listing of risks.

CRITICAL ACCOUNTING ESTIMATES

Delphi's financial statements have been prepared in accordance with Canadian general accepted accounting principles. Certain accounting policies require management to make decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Delphi's management review their estimates frequently; however, the emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. Delphi attempts to mitigate this risk by employing individuals with the appropriate skill set and knowledge to make reasonable estimates; developing internal reporting systems; and comparing past estimates to actual results.

The Company's financial and operating results include estimates of the following:

- Depletion, depreciation and accretion based on estimates of oil and gas reserves;
- Estimated revenues, operating expenses and royalties for which actual revenues and costs have not been received;
- Estimated capital expenditures on projects that are in progress;
- Estimated fair value of derivative contracts; and
- Estimated value of the asset retirement obligation including estimates of future costs and the timing of the costs.

CORPORATE GOVERNANCE

The shareholders' interests are a critical factor in the operation and management of Delphi. The Company is committed to maintaining the highest level of investor confidence in the Company through the development of its corporate governance policies. Delphi's board consists of five independent directors and two officers of the company who meet regularly to discuss matters of strategy and execution of the business plan. See Delphi's AIF for listing of committees who oversee specific aspects of the Company's operating and financial strategy.

During 2005, the Company adopted a Complaints policy. The purpose of the policy is to establish procedures for the confidential [illegible] submission by employees of complaints or concerns regarding financial statement disclosures, accounting, internal [illegible] controls, or auditing matters and for anyone else to submit complaints related to similar concerns. Any employee of the [illegible] submit, on a confidential or anonymous basis, if the employee so desires, any concerns regarding financial statement [illegible] accounting, internal accounting controls, or auditing matters; any other person may also submit similar concerns or complaints [illegible] the Chairman of the Audit Committee.

Beginning in 2005, the Company is required to issue a "Modified Certification of Annual Filings during Transition Period" [illegible] Certification) in accordance with Multilateral Instrument 52-109, Certification of Disclosures in Issuers' Annual and Interin [illegible] The Modified Certification requires certifying officers to state that they are responsible for establishing and maintaining [illegible] controls and procedures and as such have designed such procedures and evaluated their effectiveness as of the end [illegible] covered by the annual filings. Management believes the disclosure controls and procedures provide a reasonable level [illegible] that information required to be disclosed by the Company is recorded, processed, summarized and reported within [illegible] periods specified and the controls and procedures are designed to ensure that information required to be disclos[illegible] Company is accumulated and communicated to the issuer's management, including its chief executive officer [illegible] financial officer, as appropriate to allow timely decisions regarding required disclosure.

OUTLOOK

STRATEGY

Delphi emphasizes a full-cycle approach to its business and strives for internally generated development opportunities [illegible] enhancing its production base and ultimately creating value for shareholders. Delphi's goal is to become a dominant natural gas [illegible] and explorer focused in North East British Columbia and North West Alberta. The objective is to develop an inventory of [illegible] undeveloped land base so that production and reserves can be added independent of acquisition activity. In that regard, the [illegible] ability to add production through the drill bit creates a competitive advantage over those competitors that are reliant upon acquisitions to build or maintain their production base. Delphi will continue to pursue acquisitions that will be accretive on a per share basis to cash flow, production, reserves, net asset value and provide significant development opportunities to further enhance value. Delphi believes the long term fundamentals support strong commodity prices particularly in natural gas regardless of the recent price declines.

2006 CAPITAL INVESTMENT AND DEVELOPMENT ACTIVITIES

The capital program for 2006 is estimated to be $120 - $125 million with approximately 75 percent to be incurred in the first quarter. The Bigfoot Joint Venture in North East British Columbia will represent approximately 66 percent of the capital for the year. The Company's exploration program includes drilling several high impact wells representing approximately 6 percent of the capital budget. In light of the recent downturn in natural gas prices, Delphi may reduce its capital program throughout the year.

2006 PRODUCTION VOLUMES

The production outlook for 2006 will be principally impacted by the on-stream timing of new production, availability of drilling rigs, service rigs, other oil field services and anticipated drilling activity. Delphi expects to average approximately 7,000 boe/d of production based on its established capital budget of $120 - $125 million for 2006 with an exit rate of approximately 7,800 to 8,300 boe/d.

SENSITIVITIES

The following table provides estimates for 2006 of the sensitivity of the Company's cash flow to changes in a number of variables:

	Cash flow		Net earnings	
	Amount	Per share	Amount	Per share
Change of 1.0 mmcf/d in natural gas production	1,700	0.03	350	0.01
Change of $1.00 per GJ in average gas price	10,000	0.18	6,700	0.12
Change of 1 percent in interest rates	1,000	0.02	700	0.01

SEDAR FILING

Additional information about Delphi is available on the Canadian Securities Administrators' System for Electronic Distribution and Retrieval (SEDAR) at www.sedar.com and at the Company's website at www.delphienergy.ca.

auditors' report

We have audited the consolidated balance sheets of Delphi Energy Corp. as at December 31, 2005 and 2004, and the consolidated statements of earnings, and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and 2004, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 13, 2006

management's report

The financial statements of Delphi Energy Corp. were prepared by management in accordance with Canadian generally accepted accounting principles. The financial and operating information presented in this annual report is consistent with that shown in the financial statements. Management has designed and maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of financial statements for reporting purposes. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. Such estimates are based on careful judgments made by management. External auditors appointed by the shareholders have conducted an independent examination of the Company's accounting records in order to express their opinion on the financial statements. The Board of Directors is responsible for ensuring that management fulfils its responsibilities for financial and internal control. The Board exercises this responsibility through its Audit Committee. The Audit Committee, which consists of non-management members, has met with the external auditors and management in order to determine that management has fulfilled its responsibilities in the preparation of the financial statements. The Audit Committee has reported its findings to the Board of Directors who have approved the financial statements.

David J. Reid
President and Chief Executive Officer

Brian P. Kohlhammer
Vice President Finance and Chief Financial Officer

Calgary, Canada
March 13, 2006

consolidated **balance sheets**

(CDN$ thousands)

As at December 31	2005	2004
Assets		
Current assets		
Cash and cash equivalents	$ –	$ 1,892
Accounts receivable	17,907	5,675
Prepaid expenses and deposits (Note 11)	11,170	1,298
	29,077	8,865
Cash in trust (Note 8)	–	30,000
Property, plant and equipment (Note 4)	203,489	120,9[illegible]
Goodwill	12,100	12,[illegible]
Total assets	$ 244,666	$ 171,94[illegible]
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 47,752	$ 12,739
Risk management liability (Note 10)	645	–
Mezzanine debt (Note 5)	–	10,000
Bank debt (Note 6)	41,700	47,400
	90,097	70,139
Future income taxes (Note 9)	14,292	7,646
Asset retirement obligations (Note 7)	7,394	5,012
Total liabilities	111,783	82,797
Shareholders' equity		
Share capital (Note 8)	123,692	87,944
Contributed surplus (Note 8)	2,380	1,072
Retained earnings	6,811	134
Total shareholders' equity	132,883	89,150
Total liabilities and shareholders' equity	$ 244,666	$ 171,947

Contractual obligations and committments (Note 11).

See accompanying notes to the consolidated financial statements.

H.R. Lawrie

Henry R. Lawrie
Director

L. Tolley

Lamont C. Tolley
Director

consolidated statements of earnings and retained earnings

(CDN$ thousands, except per unit amounts)

For the years ended December 31	2005	2004
Revenue		
Petroleum and natural gas sales	$ 83,764	$ 24,474
Realized loss on risk management activities	(2,884)	–
	80,880	24,474
Royalties (net of Alberta Royalty Tax Credit)	(16,335)	(2,659)
Unrealized loss on risk management activities	(645)	–
	63,900	21,815
Expenses		
Operating	13,041	5,915
Transportation	4,893	1,173
General and administrative	2,491	1,587
Stock based compensation (Note 8)	1,631	599
Interest	3,658	794
Depletion, depreciation and accretion	27,094	9,003
	52,808	19,071
Earnings before taxes	11,092	2,744
Taxes (Note 9)		
Capital	250	221
Future	4,165	570
	4,415	791
Net earnings	6,677	1,953
Retained earnings (deficit), beginning of year	134	(1,819)
Retained earnings, end of year	$ 6,811	$ 134
Net earnings per share (Note 8)		
Basic and diluted	$ 0.13	$ 0.07

See accompanying notes to the consolidated financial statements.

consolidated statements of cash flows

(CDN$ thousands)

For the years ended December 31	2005	200[illegible]
Cash flow from operating activities		
Operations		
Net earnings	$ 6,677	$ 1,9[illegible]
Add non-cash items		
Depletion, depreciation and accretion	27,094	9,003
Stock based compensation	1,631	599
Unrealized loss on risk management activities	645	–
Future taxes	4,165	57[illegible]
Expenditures on site restoration and reclamation	(613)	(1[illegible])
Change in non-cash working capital (Note 12)	3,167	2,[illegible]
	42,766	14,302
Cash flow from financing activities		
Issue of shares and subscription receipts, net of issue costs	37,906	56,502
Increase (decrease) in mezzanine debt	(10,000)	10,000
Increase (decrease) in bank debt	(5,700)	23,950
Change in non-cash working capital (Note 12)	–	(1,479)
	22,206	88,973
Cash flow used in investing activities		
Capital expenditures	(61,195)	(32,633)
Acquisition of petroleum and natural gas properties (Note 3)	(51,273)	–
Corporate acquisition (Note 3)	–	(43,617)
Proceeds on disposition of petroleum and natural gas properties	5,862	–
Change in non-cash working capital (Note 12)	9,742	4,867
	(96,864)	(71,383)
Increase (decrease) in cash and cash equivalents	(31,892)	31,892
Cash and cash equivalents, beginning of year	31,892	–
Cash and cash equivalents, end of year	$ –	$ 31,892
Interest paid	$ 3,387	$ 760
Taxes paid	$ 239	$ 45

See accompanying notes to the consolidated financial statements.

notes to the consolidated financial statements

As at and for the years ended December 31, 2005 and 2004
(all tabular amounts are expressed in thousands of Canadian dollars, except per unit amounts)

NOTE 1: DESCRIPTION OF BUSINESS

Delphi Energy Corp. (the "Company" or "Delphi") is incorporated under the Business Corporations Act (Alberta) and is a public company listed on the Toronto Stock Exchange. Delphi is primarily engaged in the exploration for and development and production of natural gas properties primarily located in North West Alberta and North East British Columbia and crude oil properties in East Central Alberta.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of Delphi have been prepared by management in accordance with accounting principles generally accepted in Canada. The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reported period. Actual results may differ from these estimates.

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. Any reference to the Company refers to the Company and its subsidiaries. All inter-company transactions have been eliminated.

(B) PETROLEUM AND NATURAL GAS OPERATIONS

The Company follows the full cost method of accounting whereby all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized. Such costs include land acquisition costs, geological and geophysical costs, lease rental costs on non-producing properties, costs of both productive and unproductive drilling and production equipment. Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the depletion rate of 20 percent or more.

The accumulated costs, less the costs of acquisition of unproved properties, are depleted and depreciated using the unit-of-production method based upon total proved reserves before royalties as determined by independent evaluators. Natural gas reserves and production are converted into equivalent barrels of oil at 6:1 based upon the estimated relative energy content.

The costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of impairment is added to the costs subject to depletion.

The Company is required to perform a ceiling test at least annually to assess the carrying value of oil and gas assets. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves using forecast prices and the lower of cost and market of unproved properties exceed the carrying value of the petroleum and natural gas assets. If the carrying amount of the petroleum and natural gas assets is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost and market of unproved properties. This approach incorporates risks and uncertainties in the expected future cash flows, which are discounted using a risk free rate.

Depreciation of furniture and office equipment is provided using the declining balance method based upon estimated useful lives of 20 percent to 50 percent.

(C) INTEREST IN JOINT VENTURES

Substantially all of the Company's exploration, development and production activities are conducted jointly with others and the financial statements reflect the Company's proportionate interest in such activities.

(D) GOODWILL

Goodwill, at the time of acquisition, represents the excess of purchase price of a business over the fair value of net assets acquired. Goodwill is assessed by the Company for impairment at least each year end. If the fair value of the business is less than the book value, a

second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the business' assets and liabilities from the fair value of the business to determine the implied fair value of goodwill and comparing that amount to the book value of goodwill. Any excess of the book value of goodwill over the implied fair value is the impairment amount and will be charged to income in the period of the impairment.

(E) ASSET RETIREMENT OBLIGATIONS

The Company recognizes the fair value of an asset retirement obligation as a liability at the time it incurs a legal obligation for the future abandonment and reclamation costs associated with its petroleum and natural gas operations. Asset retirement obligations are initially measured at their fair value and subsequently adjusted to reflect the passage of time (accretion) and any changes to the estimated cash flows underlying the obligation. The associated asset retirement cost is capitalized as part of property, plant and equipment and amortized to earnings using the unit of production method over estimated proved reserves consistent with the depletion and depreciation of the underlying asset.

(F) STOCK BASED COMPENSATION

The Company records a compensation expense for all stock options granted to employees, directors or key consultants over the vesting period of the options based on the fair value method. The compensation expense is a charge to earnings and an increase to contributed surplus on the balance sheet. Consideration paid by employees, directors or key consultants upon exercise of the stock options and the amount previously recognized in contributed surplus are recorded as share capital. The Company has not incorporated an estimated forfeiture rate for stock options that will not vest, rather, the Company accounts for actual forfeitures as they occur.

(G) FUTURE INCOME TAXES

The Company follows the tax liability method of accounting for income taxes. Under this method, estimated future income tax assets and liabilities are determined based upon differences between the carrying amount as reported on the balance sheet and the tax basis of assets and liabilities and measured using substantively enacted tax rates and laws expected to be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in earnings in the period in which the change occurs. A valuation allowance is recognized against any future income tax assets if it is considered more likely than not that the asset will not be realized.

(H) FLOW-THROUGH SHARES

The resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. To recognize the foregone tax benefits to the Company, the future income tax liability and share capital are adjusted by the estimated cost of the renounced tax deduction on the date of renouncement.

(I) PER SHARE INFORMATION

Basic per share amounts are computed by dividing the net earnings by the weighted average number of common shares outstanding for the year. Diluted per share amounts reflect the potential dilution that would occur if securities or other contracts to issue common shares were exercised or converted to common shares. Diluted per share information is calculated using the treasury stock method that assumes any proceeds received by the Company upon the exercise of in-the-money stock options, plus the unamortized stock based compensation cost, would be used to buy back common shares at the average market price for the period. Anti-dilutive options or instruments are not included in the calculation.

(J) FINANCIAL INSTRUMENTS

Financial instruments consist primarily of accounts receivable, prepaid expenses, accounts payable and accrued liabilities and bank debt. There are no significant differences between the carrying value of these instruments and their estimated fair value.

The Company uses financial instruments for non-trading purposes to manage fluctuations in commodity prices, as described in Note 10. The Company has elected to mark-to-market its financial instruments.

(K) MEASUREMENT UNCERTAINTY

The amounts recorded for depletion and depreciation of petroleum and natural gas properties and equipment are based upon estimates of proved petroleum and natural gas reserves, production rates, commodity prices and future costs. The impairment test is based upon estimates of proved and, if applicable, probable reserves, production rates, petroleum and natural gas prices, future costs and other assumptions. The asset retirement obligations are based upon petroleum and natural gas reserves, future costs, expected inflation

rates and other assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes to estimates in future periods could be material.

(L) CASH AND CASH EQUIVALENTS

The Company considers deposits in banks, certificates of deposit and short-term investments with original maturities of three months or less and cash in trust as cash and cash equivalents. Bank borrowings are considered to be financing activities.

(M) REVENUE RECOGNITION

Crude oil and natural gas revenues are recognized in earnings when title passes from the Company to its customer.

NOTE 3: ACQUISITIONS

On February 1, 2005, the Company acquired producing natural gas and natural gas liquids properties with associated facilities and undeveloped land for cash consideration of $51.3 million. The Company paid for the acquisition with cash and increased bank debt.

On December 9, 2004, the Company acquired all of the issued and outstanding shares of Tercero, a private company involved in the exploration, development and production of oil and natural gas, for cash consideration of $42.5 million. The transaction was accounted for using the purchase method. The assets and liabilities have been recorded at their fair values. The accounts of the Company include the results of Tercero, which was amalgamated with the Company on February 1, 2005.

Allocated:		
Property and equipment	$	52,391
Working capital		2,173
Goodwill		9,865
Bank debt		(14,950)
Asset retirement obligations		(1,012)
Future income tax liability		(4,850)
	$	43,617

Purchase price:		
Cash consideration	$	42,532
Transaction costs		1,085
	$	43,617

NOTE 4: PROPERTY, PLANT AND EQUIPMENT

As at December 31, 2005		Cost		Accumulated depletion and depreciation		Net book value
Petroleum and natural gas properties	$	203,264	$	38,035	$	165,229
Production equipment		45,763		7,744		38,019
Furniture, fixtures and office equipment		527		286		241
	$	249,554	$	46,065	$	203,489

As at December 31, 2004						
Petroleum and natural gas properties	$	110,009	$	17,220	$	92,789
Production equipment		30,067		2,068		27,999
Furniture, fixtures and office equipment		405		211		194
	$	140,481	$	19,499	$	120,982

As at December 31, 2005, costs in the amount of $18.9 million (December 31, 2004 – $15.6 million) representing unproved properties were excluded from the depletion calculation and estimated future development costs of $9.6 million (December 31, 2004 – $7.7 million) have been included in costs subject to depletion. All costs of unproved properties have been capitalized. Ultimate recoverability of these costs will be dependent upon the finding of proved oil and natural gas reserves. The Company performed a separate impairment review of assets excluded from the ceiling test and determined that no impairment has occurred.

The Company capitalized $1.2 million (2004 – $0.5 million) of general and administrative costs directly related to exploration and development activities.

The Company disposed of two non-core properties for total proceeds of $5.9 million.

The Company performed a ceiling test calculation at December 31, 2005 to assess the recoverable value of property, plant and equipment, which indicated no write down was required. The future commodity prices used in the impairment test were based on December 31, 2005 commodity price forecasts of the Company's independent reserve engineers adjusted for differentials specific to the Company's reserves. The following table summarizes the future benchmark prices the Company used in the impairment test.

	Natural Gas		Natural Gas Liquids				Crude Oil	
	Henry Hub (US$/mmbtu)	AECO Spot (CDN$/mmbtu)	Propane (CDN$/bbl)	Butane (CDN$/bbl)	Pentanes Plus (CDN$/bbl)	West Texas Intermediate (US$/bbl)	Edmonton Light (CDN$/bbl)	Bow River Hardisty (CDN$/bbl)
2006	10.50	10.60	42.50	49.00	67.00	57.00	66.25	43.00
2007	8.75	9.25	41.00	47.25	65.25	55.00	64.00	42.50
2008	7.50	8.00	38.00	43.75	60.50	51.00	59.25	41.00
2009	7.00	7.50	35.75	41.25	56.75	48.00	55.75	39.50
2010	6.75	7.20	34.50	40.00	55.00	46.50	54.00	39.50
2011	6.50	6.90	33.50	38.75	53.25	45.00	52.25	39.75
2012	6.50	6.90	33.50	38.75	53.25	45.00	52.25	39.75
2013	6.65	7.05	34.00	39.50	54.25	46.00	53.25	40.50
2014	6.75	7.20	34.75	40.25	55.25	46.75	54.25	41.25
2015	6.90	7.40	35.50	41.00	56.50	47.75	55.50	42.25
2016	7.05	7.55	36.25	41.75	67.75	48.75	56.50	43.00
Thereafter (1)								

(1) A percentage increase of 2.00% represents the change in future prices each year after 2016 to the end of the reserve life.
(2) Prices incorporate a US/CDN $0.85 exchange rate.

NOTE 5: MEZZANINE DEBT

As at December 31	2005	2004
Mezzanine debt	$ –	$ 10,000

On February 23, 2005, the maturity date of the mezzanine debt, the Company repaid the entire principal balance and interest payable on the mezzanine debt, including the repurchase of the gross overriding royalty, for a total of $10.3 million. The repayment was funded by proceeds on the disposition of properties and bank debt.

NOTE 6: BANK DEBT

As at December 31	2005	2004
Bank debt	$ 41,700	$ 47,400

At December 31, 2005 the Company had drawn $41.7 million on its banking facility. The Company has a revolving term facility for $82.0 million with a syndicate of Canadian chartered banks (Lenders). The facility may be drawn down or repaid at any time but there are no scheduled repayment terms. The credit facility bears interest based on a sliding scale tied to the Company's trailing debt to cash flow: from a minimum of the bank's prime rate to a maximum of the bank's prime rate plus 1.0 percent. At December 31, 2005 the facility bears interest at bank prime rate plus 0.4 percent payable monthly.

In addition to the revolving term facility, the Company has a $30.0 million development facility with its Lenders to fund the Bigfoot joint venture. The Lenders will initially provide $20.0 million for the Bigfoot capital program with an additional $10.0 million to follow if the program and drilling results are progressing as expected. The pricing grid on the development facility is 0.25 percent higher than the revolving term facility.

The two facilities are secured by a $150.0 million demand floating charge debenture and a general security agreement over all assets of the Company.

NOTE 7: ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations result from working interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations, over the next three to 20 years, is approximately $13.5 million. A credit-adjusted risk-free rate of 8.0 percent and an inflation rate of 2.5 percent were used to calculate the estimated fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below.

		2005		2004
Balance, beginning of year	$	5,012	$	3,189
Liabilities incurred		950		683
Liabilities sold		(250)		–
Liabilities acquired		1,604		1,012
Liabilities settled		(613)		(186)
Change in estimate		165		–
Accretion expense		526		314
Balance, end of year	$	7,394	$	5,012

NOTE 8: SHARE CAPITAL

(A) AUTHORIZED

An unlimited number of voting common shares.

An unlimited number of preferred shares issuable in series.

(B) COMMON SHARES ISSUED

	2005			2004		
	Outstanding shares (000's)		Amount	Outstanding shares (000's)		Amount
Balance, beginning of year	47,704	$	87,944	25,218	$	29,802
Issue of flow-through common shares	4,686		26,004	2,956		10,003
Issue of common shares	2,500		14,000	9,091		20,000
Exercise of stock options	364		643	270		402
Issue of subscription receipts	–		–	10,169		30,000
Allocated from contributed surplus	–		323	–		195
Share issue costs	–		(2,741)	–		(3,902)
Future tax effect of share issue costs	–		921	–		1,444
Tax benefit renounced to shareholders	–		(3,402)	–		–
Balance, end of year	55,254	$	123,692	47,704	$	87,944

The Company issued subscription receipts late in 2004 for total proceeds of $30.0 million. As at December 31, 2004, the proceeds were being held in trust until closing of the acquisition of certain natural gas and natural gas liquids properties (Note 3 – Acquisitions). Upon closing of the acquisition on February 1, 2005, the receipts were exchanged for common shares of the Company on a 1 for 1 basis.

On March 31, 2005, the Company issued 2.7 million flow-through common shares at a price of $4.40 per share for gross proceeds of $12.0 million.

On December 13, 2005, the Company issued 1.96 million flow-through common shares at a price of $7.15 per share for gross proceeds of $14.0 million.

On December 29, 2005, the Company issued 2.5 million common shares at a price of $5.60 per share for gross proceeds of $14.0 million.

As at December 31, 2005, the Company had incurred the necessary qualifying exploration expenditures to satisfy the terms of the flow-through common shares issued during 2004. Although the Company believes it has incurred the necessary qualifying expenditures, these amounts may be subject to audit and subsequent interpretation by the Canada Revenue Agency. The Company has an obligation to incur qualifying exploration expenditures of $26.0 million by December 31, 2006 to satisfy the terms of the flow-through common shares issued during 2005. As at December 31, 2005 the Company has incurred approximately $2.0 million relating to this obligation.

(C) STOCK OPTIONS

The Company has established a stock option plan (Plan) under which it has granted options to acquire common shares to certain officers, directors, employees and key consultants. The Plan provides for the granting of options equal to ten percent of the issued and outstanding common shares of the Company. Options issued under the Plan have a term of five years to expiry and vest over a two-year period starting on the date of the grant. The exercise price of each option equals the closing market price of the Company's common shares immediately preceding the date of the grant. As of December 31, 2005 there were 2.6 million (2004 – 1.9 million) options to purchase shares outstanding.

The following table summarizes the changes in the number of options outstanding and the weighted average share prices.

	2005		2004	
	Outstanding options (000's)	**Weighted average exercise price**	Outstanding options (000's)	Weighted average exercise price
Balance, beginning of year	**1,895**	**$ 1.59**	1,852	$ 1.38
Granted	**1,165**	**3.43**	590	2.13
Exercised	**(364)**	**1.77**	(270)	1.49
Cancelled	**(67)**	**1.85**	(277)	1.48
Balance, end of year	**2,629**	**$ 2.37**	1,895	1.59
Exercisable at end of year	**1,755**	**$ 1.90**	1,094	$ 1.49

The following table summarizes information about the stock options outstanding and exercisable at December 31, 2005.

	Options outstanding			Options exercisable	
Range of exercise price	**Outstanding options** (000's)	**Weighted average exercise price**	**Weighted average remaining term**	**Exercisable** (000's)	**Weighted average exercise price**
$0.99	343	$ 0.99	2.2	343	$ 0.99
$1.45 - 1.61	844	1.46	2.5	844	1.46
$1.75 - 1.90	77	1.77	3.2	47	1.76
$2.66	200	2.66	3.9	133	2.66
$3.25 - $3.77	1,165	3.43	4.2	388	3.43
Total	2,629	$ 2.37	3.3	1,755	$ 1.90

(D) STOCK BASED COMPENSATION

The Company accounts for its stock based compensation using the fair value method for all stock options granted since January 1, 2002. For the year ended December 31, 2005, Delphi recorded non-cash compensation expense of $1.6 million (2004 – $0.6 million).

During the year ended December 31, 2005 the Company granted 1.2 million (2004 – 0.6 million) options. The fair value of all options granted during the period are estimated at the date of grant using the Black-Scholes option pricing model. The weighted average fair value of options granted during the period was $1.62 per share (2004 – $0.97). The assumptions used in the Black-Scholes model to determine fair value were as follows:

Years ended December 31	2005	2004
Risk free interest rate (%)	4.5	4.0
Expected life (years)	5.0	5.0
Expected volatility (%)	48.0	46.0

(E) CONTRIBUTED SURPLUS

The following table outlines the changes in the contributed surplus balance:

		2005		2004
Balance, beginning of year	$	1,072	$	–
Stock based compensation - adoption				668
Stock based compensation expense		1,631		599
Reclassification to common shares on exercise		(323)		(195)
Balance, end of year	$	2,380	$	1,072

(F) EARNINGS PER SHARE

Net earnings per share has been based on the following weighted average common shares:

	2005	2004
Basic	50,060	27,079
Diluted	50,931	28,053

The reconciling item between the basic and diluted weighted average common shares outstanding is stock options.

NOTE 9: INCOME TAXES

(A) EXPECTED TAX RATE

The provision for income taxes in the financial statements differs from the result that would have been obtained by applying the combined federal and provincial tax rates to the Company's earnings before taxes.

The difference results from the following items:

For the years ended December 31		2005		2004
Earnings before taxes	$	11,092	$	2,744
Statutory tax rate		37.67%		38.90%
Expected income tax expense		4,187		1,067
Crown charges		3,833		524
Resource allowance		(3,219)		(939)
Alberta Royalty Tax Credit		(103)		(38)
Stock based compensation		615		233
Attributed Canadian Royalty Income		(322)		–
Rate reduction		(187)		(272)
Other		(639)		(6)
Capital taxes		250		222
Total income taxes	$	4,415	$	791

(B) FUTURE TAX LIABILITY:

The tax effect of temporary differences that give rise to significant portions of the future tax assets and liabilities at December 31, 2005 and 2004 are presented below:

As at December 31		2005		2004
Future income tax assets				
Asset retirement obligations	$	2,486	$	1,592
Attributed Canadian Royalty Income		322		–
Risk management liability		230		–
Share issue costs		1,899		1,649
Future income tax liabilities				
Property, plant and equipment		(19,229)		(10,887)
Net future income tax liability	$	(14,292)	$	(7,646)

NOTE 10: FINANCIAL INSTRUMENTS

(A) FAIR VALUE OF FINANCIAL INSTRUMENTS

The Company's exposure under its financial instruments is limited to financial assets and liabilities, all of which are included in these financial statements. The fair values of financial assets and liabilities that are included in the balance sheet approximate their carrying amounts.

(B) CREDIT RISK

Substantially all of the Company's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. With respect to counterparties to financial instruments, the Company partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

(C) FOREIGN CURRENCY EXCHANGE RISK

The Company is exposed to foreign currency fluctuations as crude oil and natural gas prices are referenced to U.S. dollar denominated prices.

(D) INTEREST RATE RISK

The Company is exposed to interest rate risk to the extent that bank debt is at a floating rate of interest.

(E) COMMODITY PRICE RISK MANAGEMENT

The Company has a price risk management program whereby the commodity price associated with a portion of its future production is fixed. The Company sells forward a portion of its future production and enters into a combination of fixed price sale contracts with customers and commodity swap agreements with financial counterparties. The forward contracts are subject to market risk from fluctuating commodity prices and exchange rates. The contract price on physical contracts is recognized in earnings in the same period as the production revenue.

As at December 31, 2005, the Company has fixed the price applicable to future production through the following contracts:

Time period	Commodity	Type of contract	Contracted	(CDN$/GJ)
November 2005 – March 2006	Natural gas	Financial	2,000 GJ/d	$7.79 fixed
November 2005 – March 2006	Natural gas	Physical	2,000 GJ/d	$8.00 floor/$8.90 ceiling
November 2005 – March 2006	Natural gas	Physical	2,000 GJ/d	$7.50 floor/$9.65 ceiling
November 2005 – March 2006	Natural gas	Physical	1,000 GJ/d	$11.00 floor/$13.40 ceiling
November 2005 – March 2006	Natural gas	Physical	1,000 GJ/d	$12.66 floor/$14.15 ceiling (1)
April 2006 – October 2006	Natural gas	Physical	2,000 GJ/d	$9.50 floor/$10.90 ceiling
April 2006 – October 2006	Natural gas	Physical	2,000 GJ/d	$9.19 fixed
April 2006 – October 2006	Natural gas	Physical	2,000 GJ/d	$10.50 floor/$11.15 ceiling

(1) Converted at December 31, 2005 foreign exchange rate of US/CDN $0.86

As at December 31, 2005, the Company has marked-to-market its financial fixed price contracts resulting in an unrealized loss on risk management activities of $0.6 million (2004 – $nil) and an obligation of an equivalent amount.

NOTE 11: CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Company is committed, under contracts of varying lengths, for the utilization of gathering, processing and pipeline capacity on a major natural gas processing and gathering system in North East British Columbia. The future minimum commitments are as follows:

2006	$ 4,517
2007	3,945
2008	3,638
2009	3,329
2010	1,787
2011 – 2016	$ 8,935

On November 23, 2005, the Company announced a farm-in agreement with a major producer to jointly develop a natural gas resource play in the Bigfoot area of North East British Columbia. The Company will pay ninety percent of the capital expenditures up to $81.0 million to earn a 50 percent working interest on 118 sections (75,520 acres) from the partner. Pursuant to the agreement, the Company has provided the partner with a $10.0 million deposit towards these expenditures. As at December 31, 2005, Delphi has incurred $0.1 million relating to this commitment.

The Company's lease rental commitment on office premises from 2006 through 2008 is $0.1 million per annum.

NOTE 12: CHANGES IN NON-CASH WORKING CAPITAL ITEMS

For the years ended December 31	2005	2004
Change in working capital item		
Accounts receivable	$ (12,232)	$ 3,540
Prepaid expenses and deposits	(9,872)	(314)
Accounts payable and accrued liabilities	35,013	2,526
Total change in non-cash working capital	12,909	5,752
Relating to		
Operating activities	3,167	2,364
Financing activities	–	(1,479)
Investing activities	9,742	4,867
	$ 12,909	$ 5,752

NOTE 13: RECLASSIFICATION

Certain amounts have been reclassified to conform to the presentation in 2005.

our corporate information

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Delphi Energy Corp.
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Henry R. Lawrie
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Olympia Trust Company

STOCK EXCHANGE LISTING

Toronto Stock Exchange
Stock Symbol: DEE

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May 3, 2006, Calgary, Alberta

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